Copano Energy
1200 Smith Street, Suite 2300
Houston, Texas 77002
T 713 621 9547 F 713 621 9545
www.copano.com

June 5, 2012

Mr. Jeff Robinson
Chief, Air Permit Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

RE: **Application for PSD Air Quality Permit**
Greenhouse Gas Emissions
Cryogenic 3 Process Unit
Houston Central Gas Plant
Colorado County, Sheridan, Texas
Copano Processing, L.P.
TCEQ CN: 601465255
TCEQ RN: 101271419

Dear Mr. Robinson:

Copano Processing, LP (Copano) is submitting the enclosed application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions from our proposed Cryogenic 3 Process Unit at the Houston Central Gas Plant.

Registration for an Oil and Gas Facility Standard Permit was submitted to TCEQ on May 29, 2012 for this project. Copano and our consultant, RPS, are committed to working with EPA to ensure a timely review of our permit application. We are available to meet with you at your convenience in your offices to discuss the project and answer any questions you may have.

Should you have questions concerning this application, or require further information, please do not hesitate to contact me at (713) 621-9547, or Steve Langevin of RPS at (832) 239-8016.

Yours truly,

Rex Prosser
Sr. Director, EH&S Corporate

Enclosure

cc: Mr. Cody Deru, Copano Processing
Mr. Steve Langevin, RPS

411 N. Sam Houston Parkway E., Suite 400, Houston, Texas 77060-3545 USA
T +1 281 448 6188 **F** +1 281 488 6189 **W** www.rpsgroup.com

Application for Prevention of Significant Deterioration Air Permit for Greenhouse Gas Emissions

Houston Central Gas Plant
Colorado County, Sheridan, Texas

Submitted by

Copano Processing, L.P.
Houston, Texas

June 2012

Table of Contents

List of Sections

List of Tables

List of Figures

List of Appendices

Section 1
Introduction

Copano Processing, L.P. (Copano) operates a gas processing plant and associated support facilities collectively referred to as Houston Central Gas Plant (HCP), which is located in Colorado County, Sheridan, Texas. The HCP has a gas processing capacity of 1,100 million standard cubic feet per day per day (MMSCFD) and is a major source of NO_x, CO, VOC, and greenhouse gas (GHG) emissions. Copano holds TCEQ NSR Permits Nos. 56613, 17117, 17554, 96187, and various other permits by rule (PBRs) to authorize construction of existing emission sources. Federal Operating Permit (FOP) No. O-807 authorizes on-going operations.

The company proposes to expand HCP operations by installing a new 400 MMSCFD cryogenic process train. This train will consist of inlet gas mole sieve dehydrators, two supplemental heaters (HTR-3/HTR-4), a 400 MSCFD cryogenic process, a liquid amine treating unit controlled by a new Regenerative Thermal Oxidizer (RTO-3), two (2) residue turbines (TURB-5 and TURB-6), an amine storage tank (TANK-3), and associated fugitive components (CRYO3 FUG). There will also be a new vent stream (flash gas from LL Treater) routed to a previously authorized flare (FLARE).

The project qualifies for a TCEQ Non-Rule Oil and Gas Standard Permit under Title 30 Texas Administrative Code §116.620 (30 TAC §116.620). Copano has submitted a registration package to TCEQ for the Standard Permit to authorize the project. The project emissions increases and/or net emissions increases are less than the Prevention of Significant Deterioration (PSD) applicability thresholds for all pollutants except greenhouse gases (GHG). Permitting of GHG emissions in Texas is currently conducted by the USEPA Region VI; therefore, a separate PSD permit application is required to be submitted to USEPA for GHG emissions. This document constitutes Copano's application for the required GHG PSD permit. The application is organized as follows:

Section 1 identifies the project for which authorization is requested and presents the application document organization.

Section 2 contains administrative information and completed TCEQ Federal NSR applicability Tables 1F and 2F.

Section 3 contains an area map showing the facility location and a plot plan showing the location of each emission points with respect to the plant property.

Section 4 contains more details about the proposed modifications and changes in operation and a brief process description and simplified process flow diagram.

Section 5 describes the basis of the calculations for the project GHG emissions increases and includes the proposed GHG emission limits.

Section 6 includes an analysis of best available control technology for the new and modified sources of GHG emissions.

Section 7 is an additional impact analysis as required by 40 CFR 52.21(o).

Appendix A contains GHG emissions calculations for the affected facilities.

Appendix B contains a copy of the TCEQ Standard Permit registration package.

Section 2
Administrative Information and PSD Applicability Forms

This section contains the following forms:

- Administrative Information
- TCEQ Table 1F
- TCEQ Table 2F
- Table 3F

Tables 1F and 2F are federal NSR applicability forms. Because this application covers only GHG emissions, and permitting of other pollutants is being conducted by TCEQ, these forms only include GHG emissions. As shown in both the Table 1F and 2F, GHG emissions from the project exceed 75,000 tpy of CO_2e; therefore, a Table 3F, which includes the required netting analysis, is also included. The net increase in GHG emissions exceeds 75,000 tpy of CO_2e; therefore, PSD review is required.

Administrative Information

A. Company or Other Legal Name: Copano Processing, L.P.		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Mr. Rex J. Prosser		
Title: Sr. Director, EH&S Corporate		
Mailing Address: Two Allen Center, 1200 Smith Street, Suite 2300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-621-9547	Fax No.: 713-737-9081	E-mail Address: rex.prosser@copano.com
C. Technical Contact Name: Mr. Rex J. Prosser		
Title: Sr. Director, EH&S Corporate		
Company Name: Copano Processing, L.P.		
Mailing Address: Two Allen Center, 1200 Smith Street, Suite 2300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-621-9547	Fax No.: 713-737-9081	E-mail Address: rex.prosser@copano.com
D. Facility Location Information:		
Street Address: 1650 County Road 255 South		
If no street address, provide clear driving directions to the site in writing:		
City: Sheridan	County: Colorado	ZIP Code: 77475
E. TCEQ Account Identification Number (leave blank if new site or facility): CR-0020-R		
F. TCEQ Customer Reference Number *(leave blank if unknown)*: CN601465255		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN101271419		
H. Site Name: Houston Central Gas Plant		
I. Area Name/Type of Facility: Cryogenic Plant		☒ Permanent ☐ Portable
J. Principal Company Product or Business: Natural gas processing		
K. Principal Standard Industrial Classification Code: 1321		
L. Projected Start of Construction Date: 2/01/2013	Projected Start of Operation Date: 2/01/2014	
SIGNATURE		
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief.		
NAME: Mr. Rex J. Prosser, Sr. Director, EH&S Corporate		
SIGNATURE: Rex J. Prosser *Original Signature Required*		
DATE: 6/5/2012		

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date: **June, 2012**
Company: **Copano Processing L.P.**	
RN: **101271419**	Facility Location: **1650 County Road 255 South**
City: **Sheridan**	County: **Colorado**
Permit Unit I.D.: **Cryogenic Plant**	Permit Name: **Cryogenic Plant**
Permit Activity: New Source ___ Modification _X_	
Project or Process Description: **Construct new cryogenic plant at Houston Central Gas Plant**	

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS											
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	H_2S	TRS	Pb	Other[1]
	VOC	NO_x										GHG
Nonattainment? (yes or no)	No	No	No	No	No	No	No	No	NA	NA	No	NA
Existing site PTE (tpy)?	>100	>100	>100	>100	>100	>100	>100	>100				>100
Proposed project emission increases (tpy from 2F)[2]	NA	NA	NA	NA	NA	NA	NA	NA	0.0	0.0	0.00	189,742
Is the existing site a major source? [3]If not, is the project a major source by itself?	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Significance Level (tpy)	40	40	100	25	15	10	40	40	10	10	0.6	75,000
If site is major, is project increase significant?												Yes
If netting required, estimated start of construction?								1-Jan-12				
Five years prior to start of construction								1-Jan-07			contemporaneous	
Estimated start of operation								1-Oct-13				period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)												477,630
FNSR APPLICABLE? (yes or no)												Yes

1 Other PSD pollutants.

2 Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

3 Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

R J Brosse — Signature

Senior Director, EH&S Corporate — Title

6/5/2012 — Date

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant:	**GHG (CO2 Equivalents)**	**Permit No.:**	**TBD**
Baseline Period:	**NA**	**Project Name:**	**HCP Cryogenic Plant**

Affected or Modified Facilities				Permit No.	Actual Emissions (tons/yr)	A Baseline Emissions (tons/yr)	B Proposed Emissions (tons/yr)	Projected Actual Emissions (tons/yr)	Difference (B-A) (tons/yr)	Correction (tons/yr)	Project Increase (tons/yr)
	FIN	EPN	Facility Name								
1	HTR-3	HTR-3	Supplemental Gas Heater	TBD	0	0	876.7		876.7	0.0	876.7
2	HTR-4	HTR-4	Supplemental Gas Heater	TBD	0	0	876.7		876.7	0.0	876.7
3	RTO-3	RTO-3	RTO	TBD	0	0	69,452.5		69,452.5	0.0	69,452.5
4	TURB-5	TURB-5	Solar Mars 100	TBD	0	0	58,671.9		58,671.9	0.0	58,671.9
5	TURB-6	TURB-6	Solar Mars 100	TBD	0	0	58,671.9		58,671.9	0.0	58,671.9
6	CRYO3 FUG	CRYO3 FUG	Fugitives	TBD	0	0	356.9		356.9	0.0	356.9
7	FLARE	FLARE	LL Treater Flash Gas to Flare	TBD	0	0	835.5		835.5	0.0	835.5
8					-	-		-	-	-	-
9					-	-		-	-	-	-
10					-	-		-	-	-	-
11					-	-		-	-	-	-
12					-	-		-	-	-	-
13					-	-		-	-	-	-
14					-	-		-	-	-	-
15					-	-		-	-	-	-
16	-	-		-	-	-	-	-	-	-	-
										Page Subtotal[9]:	**189,742.2**
										Project Total:	**189,742.2**

Table 3F
Project Contemporaneous Changes

Company: **Copano Processing, LP**

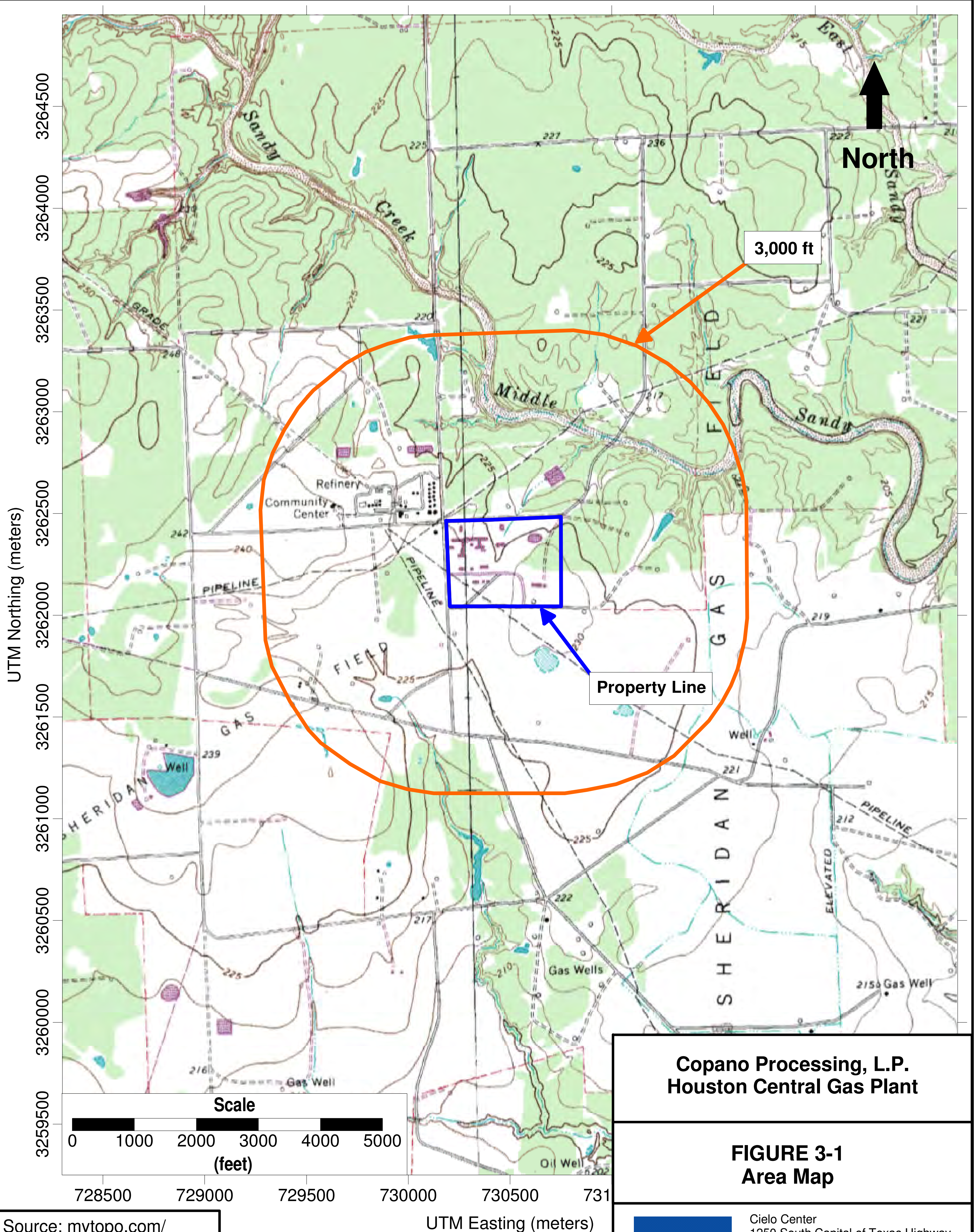
Permit Application No. **TBD**

Criteria Pollutant: **GHG**

	PROJECT DATE	EMISSION UNIT AT WHICH REDUCTION OCCURED FIN	EPN	PERMIT NUMBER	PROJECT NAME OR ACTIVITY	A PROPOSED EMISSIONS (tons / year)	B BASELINE EMISSIONS (tons / year)	C DIFFERENCE (A-B) (tons / year)	CREDITABLE DECREASE OR INCREASE (tons / year)
1	5/31/2011	TURB-3	TURB-3	96187	Solar Turbine Mars 100	58,819	0	58,819	58,819
2	5/31/2011	TURB-4	TURB-4	96187	Solar Turbine Mars 100	58,819	0	58,819	58,819
3	5/31/2011	HTR-1	HTR-1	96187	Supplemental Gas Heater	877	0	877	877
4	5/31/2011	HTR-2	HTR-2	96187	Supplemental Gas Heater	877	0	877	877
5	5/31/2011	RTO-2	RTO-2	96187	Regenerative Termal Oxidizer	58,010	0	58,010	58,010
6	1/24/2008	STKBLR3	STKBLR3	56613	Steam Boiler No. 3	110,487	0	110,487	110,487
7	1/1/2013	HTR-3	HTR-3	TBD	New Cryogenic Plant	877	0	877	877
8	1/1/2013	HTR-4	HTR-4	TBD	New Cryogenic Plant	877	0	877	877
9	1/1/2013	RTO-3	RTO-3	TBD	New Cryogenic Plant	69,452	0	69,452	69,452
10	1/1/2013	TURB-5	TURB-5	TBD	New Cryogenic Plant	58,672	0	58,672	58,672
11	1/1/2013	TURB-6	TURB-6	TBD	New Cryogenic Plant	58,672	0	58,672	58,672
12	1/1/2013	CRYO3 FUG	CRYO3 FUG	TBD	New Cryogenic Plant	357	0	357	357
13	1/1/2013	FLARE	FLARE	TBD	New Cryogenic Plant	835	0	835	835
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
								PAGE SUBTOTAL:	477,630
Summary of Contemporaneous Changes								TOTAL :	477,630

Section 3
Area Map and Plot Plan

An Area Map showing the location of the Houston Central Gas Plant is presented in Figure 3-1. A plot plan showing the location of the proposed facilities is presented in Figure 3-2.



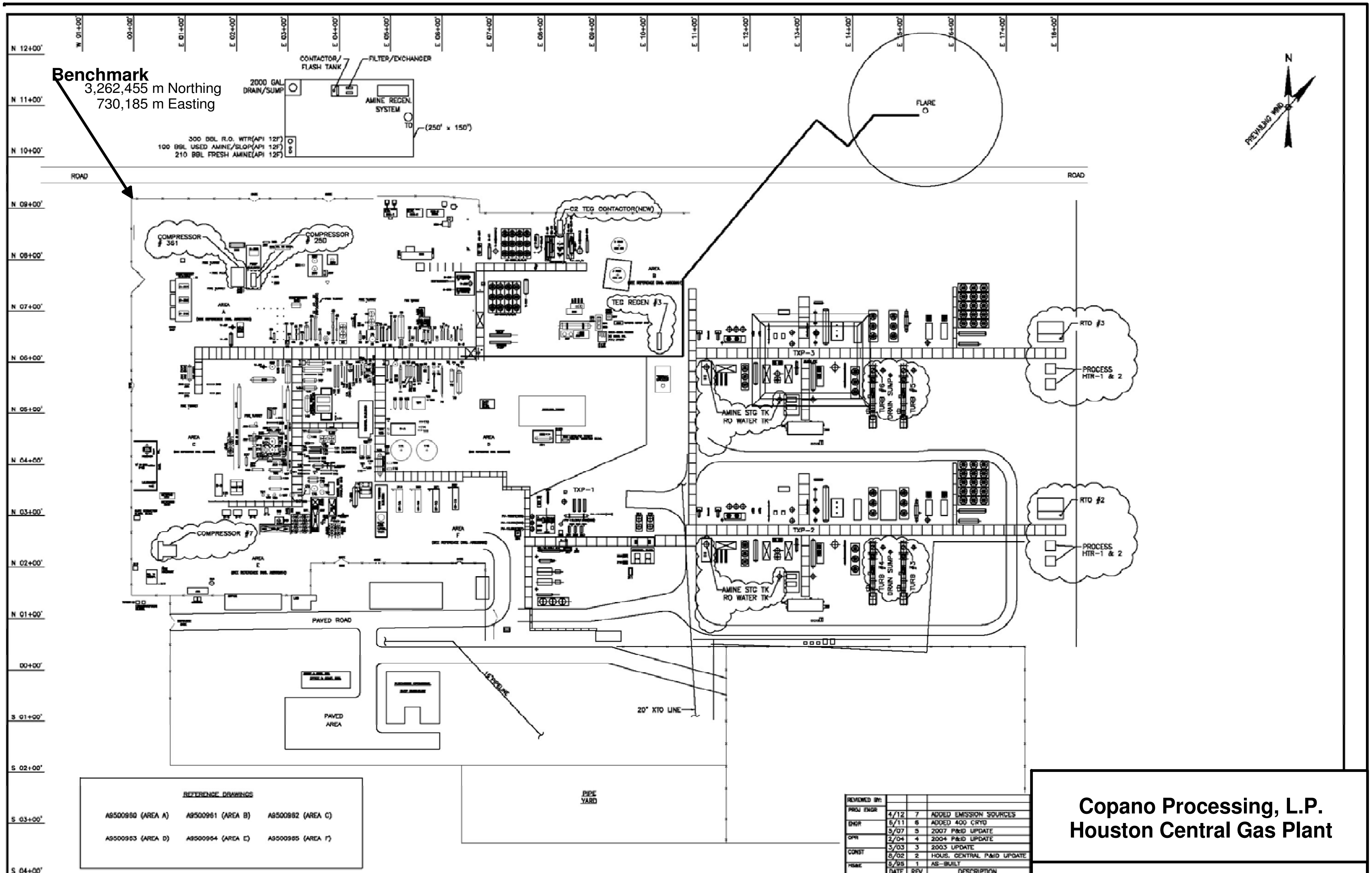
Source: mytopo.com/
Zone: 14
Coordinate Datum: NAD 83

Copano Processing, L.P.
Houston Central Gas Plant

FIGURE 3-1
Area Map

RPS

Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA



Copano Processing, L.P.
Houston Central Gas Plant

FIGURE 3-2
Plot Plan

RPS
Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA

Section 4
Process Description

4.1 Proposed New Equipment

Copano Processing, L.P. owns and operates the Houston Central Gas Plant (HCP), which is a natural gas processing, treatment, and fractionation facility that has a current nameplate capacity of 1,100 million standard cubic feet per day (MMSCFD). Copano is proposing to add an additional 400 MMSCFD cryogenic process, bringing the total plant capacity up to 1.5 billion standard cubic feet per day (BSCFD).

High pressure natural gas from the inlet pipeline will enter the plant, where it is first dehydrated through a molecular sieve dehydrator. After dehydration, the dry gas will then be processed through a cryogenic process, removing the natural gas liquids (NGLs) from the gas. The NGLs are then sent through the site's existing fractionation columns. The residue gas from the cryogenic process will then be compressed and sent to sales. The compressors are driven by two new gas-fired combustion turbines. The liquids will be treated in a liquid amine treating unit (LL Treater), where CO_2 and trace amounts of H_2S will be removed from the NGLs. The acid gas (mostly CO_2 along with minor concentrations of H_2S and hydrocarbons) will then be routed to a new regenerative thermal oxidizer.

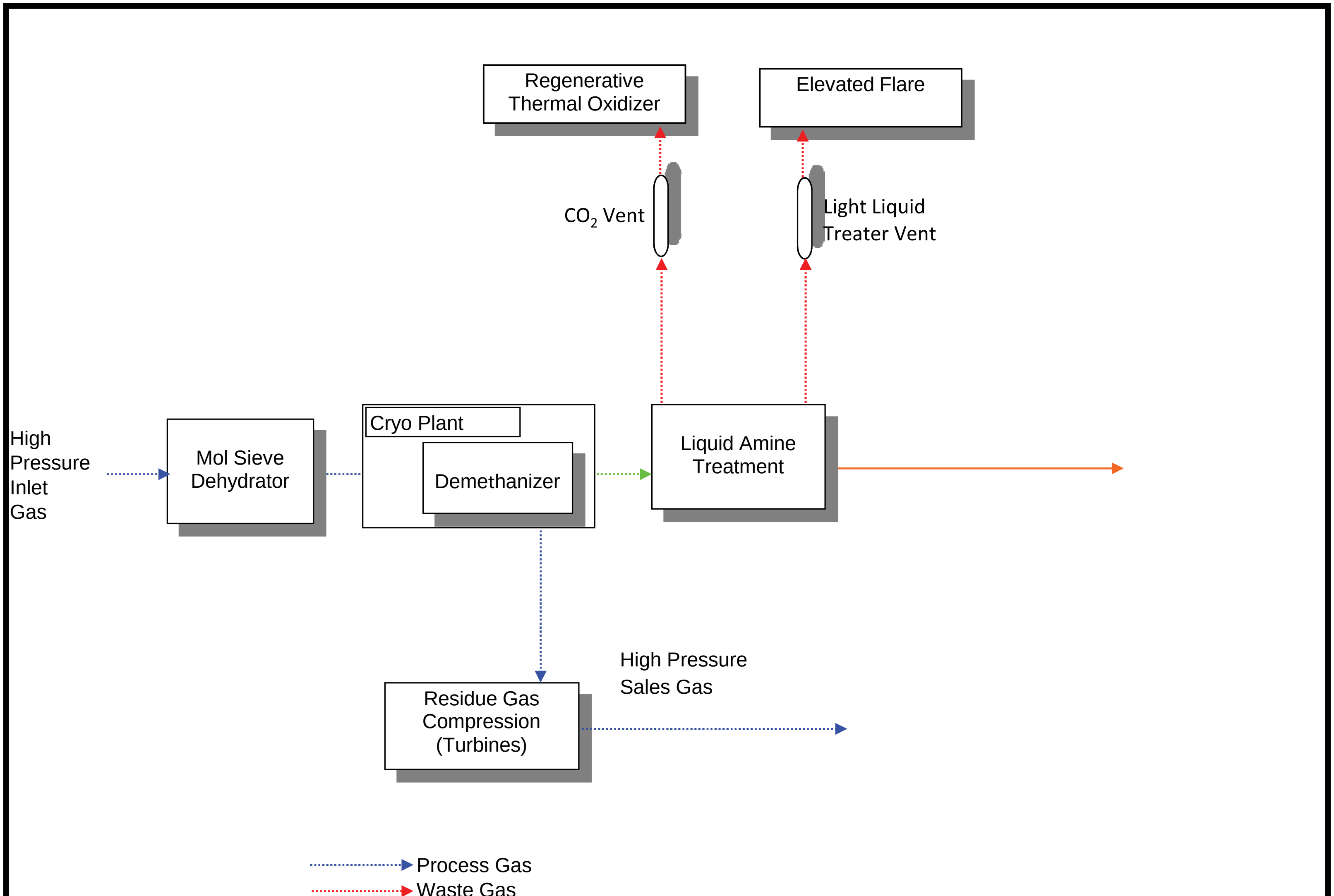
New project air emission sources consist of two supplemental gas-fired heaters (HTR-3 and HTR-4), a LL Treater controlled by a new Regenerative Thermal Oxidizer (RTO-3), an amine storage tank (TANK-3), two (2) Solar Mars 100 combustion turbines (TURB-5 and TURB-6) used for compression of the residue gas, fugitive piping components (CRYO3 FUG), and flaring of flash gas from the vent from the flasher in the LL Treater process. The flare (FLARE) has been previously authorized under TCEQ Standard Permit No. 101369. A process flow diagram for the proposed new equipment is shown in Figure 4-1.

4.2 Existing Equipment

The existing HCP processes 1,100 MMSCFD of gas. Raw natural gas enters the plant from two high pressure sources and one low pressure source. The high pressure gas sources enter the plant at 1,000 psig. The low pressure gas source (approximately 7% of total gas inlet) from field production wells enters the plant, where it is compressed by the inlet gas compressors to 1,000 psig, then sent through an amine treating unit to remove CO_2 and trace amounts of H_2S. The acid gas from the amine treating unit (mostly CO_2 along with minor concentrations of H_2S and hydrocarbons) is routed to the site's existing regenerative thermal oxidizers. The treated gas is then dehydrated by the glycol dehydration system, which consists of an ethylene glycol treater and two triethylene glycol treaters. The overhead vapors from the dehydrators are routed back to a condenser unit. Uncondensed vapors from the condenser are vented to the plant's low pressure flare system. Emissions from the dehydration system intermediate flash tanks are recycled back into the plant fuel system.

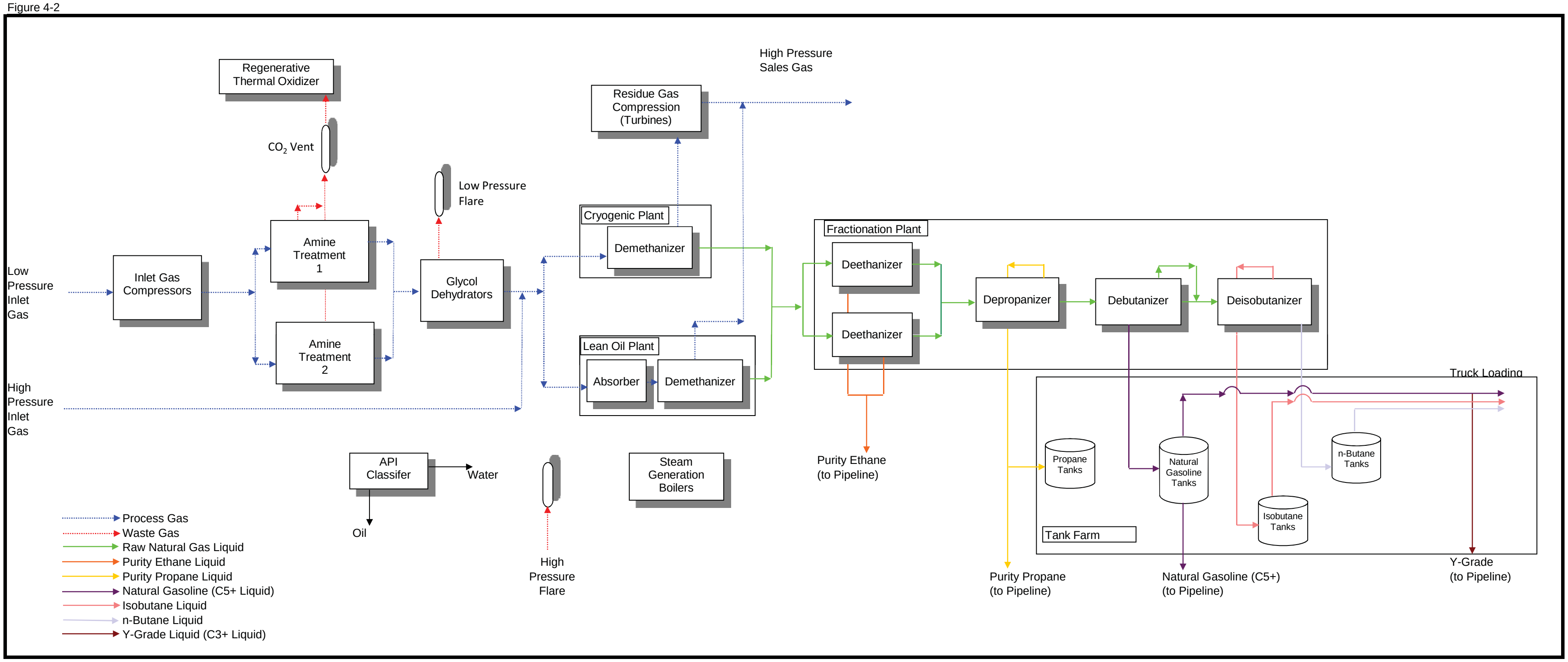
The dry, treated gas is then mixed with the two high pressure sources and sent on to a lean oil absorption process plant and a cryogenic process plant to process the natural gas and remove the NGLs. The residue gas is compressed and sent to sales. Some of the y-grade NGLs are then sent to the fractionation plant and separated into individual liquid products (ethane, propane, n-butane, isobutane, and natural gasoline (C5+)). The remaining y-grade and fractionated products are sent offsite via pipeline. The isobutene and n-butane are sent offsite via truck.

Steam generated from utility boilers is used for various processes in the plant, such as regenerating spent glycol in the dehydration system. A wastewater basin is used to collect wastewater runoff. This wastewater runoff is then treated with an API oil and water separator. There will be no change to these existing systems from this proposed expansion. A process flow diagram for the existing process is shown in Figure 4-2.



Copano Processing, L.P.
Houston Central Gas Plant
New Cryogenic Train
Figure 4-1 Process Flow Diagram

Copano Processing, L.P.
Houston Central Gas Plant
Existing Process Flow Diagram
Figure 4-2



Section 5
Emission Rate Basis

This section contains a description of the increases in GHG emissions from new facilities associated with the project. GHG emission calculations methods are also described, and the resulting GHG emission rates are presented in Table 5-1 for each emission point. Emissions calculations are included in Appendix A.

5.1 Combustion Turbines

There will be two new natural gas fired combustion turbines used for residue gas compression included for the project (EPNs TURB-5 and TURB-6). The compressor turbines are Solar Mars 100 combustion turbines that each has a nominal rated capacity of 15,000 HP.

Annual GHG emissions were calculated based on the maximum fuel firing rate of each turbine occurring continuously (8,760 hr/yr) all year. Emissions of CO_2, CH_4, and N_2O were calculated using the default emission factors for natural gas from Tables C-1 and C-2 of Appendix A to 40 CFR Part 98, Subpart C. The emissions calculations are included in Table A-1 of Appendix A to this permit application.

5.2 Heaters

There will be two new natural gas fired heaters (EPNs HTR-3 and HTR-4) installed to support the project. The heaters will each have a capacity of 25 MMBtu/hr (HHV) and will be operated no more than 600 hr/yr each. Emissions of CO_2, CH_4, and N_2O were calculated using the default emission factors for natural gas from Tables C-1 and C-2 of Appendix A to 40 CFR Part 98, Subpart C. The emissions calculations are included in Table A-1 of Appendix A to this permit application.

5.3 RTO

The new RTO used to control trace VOC and H_2S in the acid gas stream from the amine unit will emit CO_2 that is in the acid gas as well as CO_2 from combustion of the VOCs in the stream and CO_2 and other GHGs from combustion of natural gas burned in the pilots. CO_2 emissions from the CO_2 in the vent stream were calculated by multiplying the inlet CO_2 concentration by the flow rate of the stream. CO_2 emissions from oxidation of the VOCs were calculated from the inlet VOC composition and 100% conversion of each compound to CO_2. Emissions of CO_2,

CH_4, and N_2O from natural gas burned in the pilots were calculated using the default emission factors for natural gas from Tables C-1 and C-2 of Appendix A to 40 CFR Part 98, Subpart C. The emissions calculations are included in Table A-2 of Appendix A to this permit application.

5.4 Flare Emissions

Flash gas from the LL Treater routed to an existing flare (EPN FLARE) contains VOCs and small amounts of CO_2. CO_2 emissions from the CO_2 in the flash gas were calculated by multiplying the inlet CO_2 concentration by the flow rate of the stream. CO_2 emissions from oxidation of the VOCs were calculated from the inlet VOC composition and 100% conversion of each compound to CO_2. The emissions calculations are included in Table A-3 of Appendix A to this permit application.

5.5 Process Fugitive Emissions

Process fugitive (equipment leak) emissions consist of methane from the new piping components in the new cryogenic plant (EPN CRYO3 FUG). The 28M leak detection and repair (LDAR) program will be applied to the new piping components associated with the Project. All emissions calculations utilize current TCEQ factors and methods in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.* Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). Uncontrolled emission rates were obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate Oil and Gas Production Operations emission factor. To obtain controlled fugitive emission rates, the uncontrolled rates were multiplied by a control factor, which was determined by the 28M LDAR program. The methane emissions were then calculated by multiplying the total controlled emission rate by the weight percent of methane in the process streams. The fugitive emissions calculations are included in Table A-4 of Appendix A.

Table 5-1 Proposed GHG Emission Limits (CO_2e)

EPN	Description	tpy
HTR-3	Supplemental Gas Heater	877
HTR-4	Supplemental Gas Heater	877
RTO-3	Regenerative Thermal Oxidizer	69,452
TURB-5	Solar Mars 100	58,672
TURB-6	Solar Mars 100	58,672
CRYO3 FUG	Fugitives	357
FLARE	LL Treater Flash Gas to Flare	835

Section 6
Best Available Control Technology

PSD regulations require that the best available control technology (BACT) be applied to each new and modified facility that emits an air pollutant for which a significant net emissions increase will occur from the source. The only PSD pollutant addressed in this permit application is GHG. The new facilities associated with the project that emit GHGs include two natural gas fired combustion turbines (EPNs TURB-5 and TURB-6), two small gas-fired heaters (EPNs HTR-4 and HTR-4), one new regenerative thermal oxidizer (EPN RTO-3), and new process fugitives (EPN CRYO3 FUG). A small vent stream will also be sent to a previously authorize flare (EPN FLARE) for control of VOCs in the stream. Routing this stream to the flare is considered to be a modification of the flare for PSD purposes. BACT applies to each of these new and modified sources of GHG emissions.

The U.S. EPA-preferred methodology for a BACT analysis for pollutants and facilities subject to PSD review is described in a 1987 EPA memo (U.S. EPA, Office of Air and Radiation Memorandum from J.C. Potter to the Regional Administrators, December 1, 1987). This methodology is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. In addition, a control technology must be analyzed only if the applicant opposes that level of control.

In an October 1990 draft guidance document (*New Source Review Workshop Manual (Draft*), October 1990), EPA set out a 5-step process for conducting a top-down BACT review, as follows:

1) Identification of available control technologies;

2) Technically infeasible alternatives are eliminated from consideration;

3) Remaining control technologies are ranked by control effectiveness;

4) Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and

5) Selection of BACT.

In its *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010), EPA reiterates that this is also the recommended process for permitting of GHG emissions under the PSD program. As such, this BACT analysis follows the top-down approach.

6.1 Combustion Turbines

6.1.1 Step 1 – Identification of Potential Control Technologies

A search of EPA's RACT/BACT/LAER Clearinghouse was conducted for small natural gas turbines in the size range of those proposed for Copano's new cryogenic plant, and no entries were found for GHG emissions. However, based on process and engineering knowledge and judgment and permit applications that have been submitted to EPA Region 6 for similar facilities, several potentially applicable GHG control technologies were identified for consideration in this BACT analysis. These technologies include the following:

- Periodic Maintenance and Tune-up – Periodic tune-up of the turbines to maintain optimal thermal efficiency. After several months of continuous operation of the combustion turbines, fouling and degradation results in a loss of thermal efficiency. A periodic maintenance program consisting of inspection of key equipment components and tune up of the combustor will restore performance to original or near original conditions. Solar Turbines, the manufacturer of the proposed turbines, has an extensive inspection and maintenance program that Copano implements on existing turbines at the HCP.
- Turbine Design – Good turbine design to maximize thermal efficiency.
- Instrumentation and Controls – Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions.
- Waste Heat Recovery – Use of heat recovery from the turbine exhausts to provide process heat for use at the plant.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2.

6.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered "technically" feasible for the proposed turbines. Proper instrumentation and controls, high efficiency turbine design, waste heat recovery, and periodic maintenance and tune-ups are all used on existing turbines at the Copano HCP and have been incorporated into the design of the proposed turbines and are thus considered viable for the proposed facilities.

Carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from natural gas fired facilities. This conclusion is supported by the BACT example for a natural gas fired boiler in Appendix F of EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010). In the EPA example, CCS is not even identified as an available control option for natural gas fired facilities. Also, on pages 33 and 44 of the Guidance Document, it states:

> "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is available for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs."

A project implementing CCS was in the permitting stage at the time of this application submittal. This project is the Indiana Gasification Project, and it differs from Copano's project in several significant ways. The project will gasify coal, producing significantly more CO_2 than the Copano combustion turbines, with the primary product being substitute natural gas (SNG), or methane. When coal is gasified, the product is a mixture consisting primarily of CO, CO_2, and H_2. Then, in the SNG process, a series of reactions converts the CO and H_2 to methane. To meet pipeline specifications, the CO_2 must be removed from the SNG, which produces a relatively pure CO_2 stream that is naturally ready for sequestration. Combustion of natural gas as with Copano's project, produces an exhaust stream that is less than 10% CO_2, which is far from pure CO_2. Thus, while the Indiana Gasification product will naturally produce a CO_2 byproduct that is amenable to sequestration or use in enhanced oil recovery without further processing, the Copano turbines will not. Separation (purification) of the CO_2 from the turbine combustion exhaust streams requires additional costly steps not otherwise necessary to the process. As a final point, the viability of the Indiana Gasification Project is highly dependent on a 30-year contract requiring the State of Indiana to purchase the SNG produced and federal loan guarantees should the plant fail. In contrast, Copano's project relies on market conditions for viability and is not guaranteed by the government.

The CO_2 streams included in this permit application are similar in nature to the gas-fired industrial boiler in the EPA Guidance Appendix F example and are dilute streams, and thus are not among the facility types for which the EPA guidance states CCS should be listed in Step 1.

The inference from the above citation is that for other types of facilities, CCS does not need to be listed as an available option in Step 1. However, for completeness purposes, Copano has assumed that CCS is a viable control option.

6.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies that were considered for controlling GHG emissions from the proposed turbines in order of most effective to least effective include:

- CO_2 capture and storage,
- Waste heat recovery,
- Instrumentation and control system, and
- Periodic maintenance and tune-ups.

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus is considered to be the most effective control method.

Exhaust waste heat recovery systems are capable of producing about 43 MMBtu/hr of process heat from each turbine. The required heat duty for the process which would utilize the recovered heat ranges from about 40 MMBtu/hr to 65 MMbut/hr. Based on an 80% efficient process heater, this equates to a heat input range of about 50 MMBtu/hr to 80 MMBtu/hr. Supplying this heat with waste heat recovery systems is equivalent to an overall reduction in fuel combustion of between 18% and 26% compared to the combined firing rate of the two turbines and a heater that would otherwise be required.

An instrumentation and control package to continuously monitoring of the turbine package ensures the turbine is operating in the most efficient manner. Instrumentation and controls include:

- Gas flow rate monitoring,
- Fuel gas flow and usage,
- Exhaust gas temperature monitoring,
- Pressure monitoring around the turbine package,
- Temperature monitoring around the turbine package,
- Engine temperature monitoring,
- Vibration monitoring,
- Air/fuel ratio monitoring,

- Waste Heat Recovery Unit temperature and pressure monitoring, and
- Third party quarterly stack testing to ensure emissions are in compliance.

Currently, periodic maintenance and tune-ups of existing turbines are performed per the manufacturer's recommended program. This program is consists thorough inspection and maintenance of all turbine components on a daily, monthly, semi-annual, or annual frequency depending on the parameter or component and as recommended by Solar. The effectiveness of this control option cannot be directly quantified, and is therefore ranked as the least effective alternative.

6.1.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

A brief evaluation of each technically feasible combustion turbine control option follows.

CCS. The technology to capture and store CO_2 in permanent underground storage facilities exists and has been used in limited applications, but as stated previously, is not economically viable for most commercial applications. However, since the technology has been demonstrated on some processes and is potentially feasible for the proposed turbines, it cannot be completely ruled out based only on technical infeasibility; therefore, a cost effective analysis was performed for this option. The results of the analysis, presented in Table 6-1, show that the cost of CCS for the project would be approximately $104 per ton of CO_2 controlled, which is not considered to be cost effective for GHG control. This equates to a total cost of about $10,900,000 per year the two turbines. The estimated total capital cost of the Cryo 3 Project is $145,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an annualized cost of about $13,700,000 for the project alone. Thus, the annualized cost of CCS would almost double the cost of the project; therefore, CCS would make the project economically unviable and is rejected as a control option on the basis of excessive cost.

There are additional negative impacts associated with use of CCS. The additional process equipment required to separate, cool, and compress the CO_2 would require a significant additional power and energy expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy must be provided from additional combustion units, including heaters, engines, and/or combustion turbines. Electric driven compressors could be used to partially eliminate additional emissions from the HCP, but significant additional GHG emissions, as well as additional criteria pollutant (NO_x, CO, VOC, PM, SO_2) emissions, would occur from the associated power plant that produces the electricity. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system if the emissions were also captured for sequestration or reduce the net amount GHG emission reduction, making CCS even less cost effective than shown in Table 6-1.

Based on both the excessive cost effectiveness in $/ton of GHG emissions controlled and the inability of the project to bear the high cost and the associated negative environmental and energy impacts, CCS is rejected as a control option for the proposed project.

Instrumentation and Controls. Instrumentation and controls that can be applied to the combustion turbines are identified in Section 6.1.3 and are considered an effective means of control for the proposed turbine configuration.

Waste Heat Recovery. Heat recovery systems designed to recover and utilize the waste heat in the turbine exhaust is capable of eliminating about 40 MMBtu/hr of fired heater capacity that would otherwise be required for the process. This corresponds to up to about 21,000 tpy of GHG emissions reductions (estimated GHG emissions from a natural gas fired heater operated 8,760 hr/yr).

Periodic Maintenance and Tune-ups. Periodic maintenance and tune-ups of the turbines include:

- Preventive maintenance check of fuel gas flow meters annually,
- Cleaning of combustors on an as-needed basis, and
- Implementation of manufacturer's recommended inspection and maintenance program.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement.

6.1.5 Step 5 – Selection of BACT

As previously stated, air/fuel controls and efficient combustion turbine design, waste heat recovery, and tune-ups performed as needed are currently utilized on the existing turbines at the HCP to maximize efficiency and thus reduce GHG emissions. These control practices are also included in the design of the new turbines and are thus part of the selected BACT. The following additional BACT practices are proposed for the turbines:

- Determine CO_2e emissions from the turbines based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance,
- Good turbine design to maximize efficiency,

- Install and operate a Waste Heat Recovery Unit (WHRU) with a capacity of about 43 MMBtu/hr on each turbine to recovery heat from the turbine exhaust. These systems will eliminate the need for a fired stand alone heat medium heater and will provide sufficient heat for the Inlet Gas Heater, Regeneration Gas Heater, Amine Reboiler, and Trim Reboiler.
- instrumentation and control package including:
  - Gas flow rate monitoring,
  - Fuel gas flow and usage,
  - Exhaust gas temperature monitoring,
  - Pressure monitoring around the turbine package,
  - Temperature monitoring around the turbine package,
  - Engine temperature monitoring,
  - Vibration monitoring,
  - Air/fuel ratio monitoring,
  - Waste Heat Recovery Unit temperature and pressure monitoring, and
  - Third party quarterly stack testing to ensure emissions are in compliance.
- Implement Solar's recommended comprehensive inspection and maintenance program for the turbines,
- Clean combustors as needed,
- Calibrate and perform preventive maintenance on the fuel flow meter once per year, and
- Limit GHG emissions from the turbines to 1.16 tons of CO_2e/MMscf of residue gas compressed, on a 12-month rolling average basis.

6.2 Heaters

6.2.1 Step 1 – Identification of Potential Control Technologies

The potentially applicable technologies to minimize GHG emissions from the heaters include the following:

- Periodic Tune-up – Periodically tune-up of the heaters to maintain optimal thermal efficiency.
- Heater Design – Good heater design to maximize thermal efficiency,
- Heater Air/Fuel Control – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.
- Waste Heat Recovery – Use of heat recovery from the heater exhausts to preheat the heater combustion air or process streams in the unit.

- Use of Low Carbon Fuels – Fuels vary in the amount of carbon per btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.

- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

The proposed heaters are small (25 MMBtu/hr each) and will only be operated up to 600 hours year each. As a result, each heater will emit less than 900 tpy of CO_2e, which is about 0.5% of the total project CO_2e emissions. Waste heat recovery is not applicable to intermittently operated combustion units, and is therefore rejected for the heaters. Carbon capture and storage is also not a practical or economically feasible add-on option for very small intermittent sources, and was also eliminated. Automated air/fuel controls would not result in any appreciable increase in heater efficiency or resulting GHG emission reduction due to the already insignificant amount of GHG emissions from the heaters, and was therefore also rejected as a viable control options. The remaining control options identified in Step 1 have a minor degree of applicability and have therefore been retained for further consideration, although the potential for any significant emission reduction does not exist due to the already low emission rates.

6.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies applicable to the proposed heater design in order of most effective to least effective include:

- Use of low carbon fuels (up to 100% for fuels containing no carbon),
- Heater Design (up to 10%), and
- Periodic tune-up (up to 10% for boilers; information not found for heaters).

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Fuels used in industrial process and power generation typically include coal, fuel oil, natural gas, and process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emission factor in lb/MMBtu about 55% of that of subbituminous coal. Process fuel gas is a byproduct of chemical process, that typically contains a higher fraction of longer chain carbon compounds than natural gas and thus results in more CO_2 emissions. Table C-2 in 40 CFR Part 98 Subpart C, which contains CO_2 emission factors for a variety of fuels, gives a CO_2 factor of 59 kg/MMBtu for fuel gas compared to 53.02 kg/MMBtu for natural gas. Of over 50 fuels identified in Table C-2, coke oven gas, with a CO_2 factor of 46.85

kg/MMBtu, is the only fuel with a lower CO_2 factor than natural gas, and is not viable fuel for the proposed heaters as the HCP does not contain coke ovens. Although Table C-2 includes a typical CO_2 factor of 59 kg/MMBtu for fuel gas, fuel gas composition is highly dependent on the process from which the gas is produced. Some processes produce significant quantities of hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100%. Hydrogen fuel, in any concentration, is not a readily available fuel for most industrial facilities and is only a viable low carbon fuel at industrial plants that generate hydrogen internally. Hydrogen is not produced from the processes at the HCP, and is therefore not a viable fuel. Natural gas is the lowest carbon fuel available for use in the proposed heaters.

Good heater design and periodic tune-ups have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as new equipment; thus, the higher end of the range of stated efficiency improvements that can be realized is assumed to apply to the existing (older) facilities, with the lower end of the range being more applicable to new heater designs.

6.2.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Use of Low Carbon (Natural Gas) Fuel. Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is readily available at the HCP and is currently considered a very cost effective fuel alternative. Natural gas is also a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. Natural gas is the fuel of choice for most industrial facilities, especially natural gas processing facilities, in addition to being the lowest carbon fuel available. Although use of natural gas as fuel results in about 28% less CO_2 emissions than diesel fuel and 45% less CO_2 emissions than subbituminous coal; it is more prudent to consider natural gas to be the “baseline” fuel for this BACT analysis; thus, claiming an emission reduction from its use would be a misrepresentation.

Heater Design. New heaters can be designed with efficient burners and state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. Due to the very low energy consumption of these small intermittently used heaters, only basic heater efficiency features are practical for consideration in the heater design.

Periodic Heater Tune-ups. Periodic tune-ups of the heaters include:

- Preventive maintenance check of fuel gas flow meters,
- Preventive maintenance check of oxygen control analyzers,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range. Due to the minimal use of these heaters, regularly scheduled tune-ups and inspections are not warranted.

6.2.5 Step 5 – Selection of BACT

Efficient heater design, use of natural gas, and tune-ups performed as needed are proposed as BACT for the heaters as detailed below.

- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed heaters. It is the lowest carbon fuel available for use at the HCP.
- Good heater design and operation to maximize thermal efficiency and reduce heat loss to the extent practical for heaters of this size in intermittent service
- Use of manual air/fuel controls to maximize combustion efficiency.
- Clean and inspect heater burner tips and perform tune-ups as needed and per vendor recommendations.

6.3 RTO

The acid gas stream from the amine treating unit, consisting primarily of CO_2, contains VOCs and H_2S that must be controlled prior to venting the stream to the atmosphere. Copano proposes to use a regenerative thermal oxidizer (RTO) to control this stream. The advantages of an RTO are that it has a high destruction efficiency and it requires no supplemental natural gas to combust the waste stream. The BACT analysis looked at other options to the RTO.

6.3.1 Step 1 – Identification of Potential Control Technologies

The options considered for controlling the acid gas stream include:

- Use of a well designed RTO,

- Instrumentation and controls to ensure efficient operation of RTO,
- Inspection and maintenance of RTO,
- Use of a flare, and
- Carbon capture and sequestration.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

All of the identified control options are considered to be technically feasible.

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The control options are ranked from most effective to least effective as follows:

- Carbon capture and sequestration,
- Use of an RTO including instrumentation and control packate and manufacturer's inspection and maintenance program, and
- Use of a flare.

6.3.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Carbon Capture and Sequestration (CCS). The viability of CCS has been discussed previously in Section 6.1 and is not considered a viable option at this time. However, for completeness, a cost analysis for CCS applied to acid gas stream was conducted and is presented in Table 6-2. The total estimated capital cost of CCS applied to this stream only is $50,000,000. This cost is over one-third of the $145,000,000 cost of the proposed project and would thus make the project economically unviable. In addition, the cost effectivenss of this control option is estimated to be $89 per ton of CO_2e controlled, which is also considered to be an excessive cost for GHG emission control. Based on these excessive costsm CCS was rejected from further consideration as a control option for this stream.

Use of an RTO. A well designed RTO is a proven technology to treat streams such as the amine unit acid gas stream. Copano currently utilizes this technology on similar units at the HCP, and it has proven to be a successful and fuel efficient control option with no significant negative environmental or energy impacts. The RTO is capable of achieving 99% destruction of VOCs and 99.8% destruction of H_2S. Use of an RTO eliminates the need for supplemental natural gas to maintain proper combustion. The only expected natural gas usage is for the pilot, which will have an annual average firing rate of about 1 MMBtu/hr, which results in a very minimal 512 tpy of CO_2e emissions.

Use of a flare. Due to the low heat content of the acid gas stream, use of a flare would require significant supplemental natural gas to maintain complete combustion. An estimated 55 MMBtu/hr of natural gas would be required to maintain proper combustion. Combustion of this amount of natural gas would result in an additional 29,000 tpy of CO_2e emissions to the atmosphere. The maximum destruction efficiency that could be achieved with a flare is 98% for both VOC and H_2S compared to 99% for VOC and 99.8% for H_2S with the use of an RTO.

Because a flare would be a less effective means of control and would result in more GHG emissions than an RTO, it was rejected from consideration.

6.3.5 Step 5 – Selection of BACT

Copano proposes to utilize a well designed and operated RTO to treat the amine unit acid gas stream. Natural gas is only required for the pilot, which will produce a negligible 512 tons of GHG emissions as CO_2e. Therefore, an RTO produces no significant additional GHG emissions beyond what is already present in the acid gas stream. The design and operation of the RTO will include the following:

- instrumentation and control package including:
  - Acid gas vent stream flow rate monitoring,
  - Fuel gas flow and usage,
  - RTO temperature monitoring, and
  - Pressure monitoring around the RTO package;
- Implement vendor's recommended comprehensive inspection and maintenance program for the RTO;
- Clean RTO as needed; and
- Calibrate and perform preventive maintenance on RTO instruments and control package once per year.

6.4 Flash Gas Flaring

GHG emissions, primarily CO_2, are generated from the combustion of the LL Treater flash gas stream in a previously authorize flare. GHG emissions from this stream are only 835 tpy; therefore, use of additional measures or alternate controls to reduce emissions will not significantly change total project GHG emissions. However, for completeness, BACT is addressed below.

6.4.1 Step 1 – Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions from flaring is minimizing the quantity of flared waste gas and natural gas to the extent possible. The technically viable options for achieving this include:

- Flaring minimization – minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practice.
- Proper operation of the flare – use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2.

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

Both flaring minimization and proper operation of the flare are considered technically feasible.

6.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Flare minimization and proper operation of the flare are potentially equally effective but have case-by-case effectiveness that cannot be quantified to allow ranking.

6.4.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Use of an analyzer(s) to determine the heating value of the flare gas to allow continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf to insure proper destruction of VOCs ensures that excess natural gas is not unnecessarily flared. This added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental impacts associated with this option.

Proper design of the process equipment to minimize the quantity of waste gas sent to the flare also has no negative economic or environmental impacts.

6.4.5 Step 5 – Selection of BACT

Copano proposes use of both identified control options to minimize GHG emissions from flaring of the LL Treater flash gas stream. A gas analyzer will be utilized to measure the BTU value of the flash gas stream. Natural gas will be added as required to maintain the heating value of the combined flash gas and natural gas stream above 300 btu/scf. The efficient use of natural gas will avoid the production of both unnecessary GHG emissions as well as criteria pollutants. The proposed process facilities will be designed to minimize the volume of the flash gas stream sent to the flare.

6.5 Process Fugitives

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from processes fugitives have been conservatively estimated to be 357 tpy as CO_2e. This is a negligible contribution to the total GHG emissions; however, for completeness, they are addressed in this BACT analysis.

6.3.1 Step 1 – Identification of Potential Control Technologies

The only identified control technology for process fugitive emissions of CO_2e is use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions; however, due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

6.3.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. However, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. Copano uses TCEQ's 28M LDAR program at the HCP to minimize process fugitive VOC emissions at the plant, and this program has also been proposed for the additional fugitive VOC emissions associated with the project.

6.3.5 Step 5 – Selection of BACT

Due to the negligible amount of GHG emissions from process fugitives, the only available control, implementation of an LDAR program, is clearly not cost effective, and BACT is determined to be no control. However, Copano will implement TCEQ's 28M LDAR program for VOC BACT purposes, which will also effectively minimize GHG emissions. Therefore, the proposed VOC LDAR program more than satisfies GHG BACT requirements.

Table 6-1
Approximate Cost for Construction and Operation of a Post-Combustion CCS System for Combustion Turbine Emissions

CCS System Component	Cost ($/ton of CO_2 Controlled)[1]	Tons of CO_2 Controlled per Year[2]	Total Annualized Cost
CO_2 Capture and Compression Facilities	$103	105,609	$10,877,777
CO_2 Transport Facilities[3]	Not Included	Not Included	Not Included
CO_2 Storage Facilities	$0.51	105,609	$53,861
Total CCS System Cost	$104	105,609	$10,931,638

Proposed Plant Cost	Total Capital Cost	Capital Recovery Factor[4]	Annualized Capital Cost
Cost of CRYO3 Plant without CCS[5]	$145,000,000	0.0944	$13,686,974

1. Costs are from *Report of the Interagency Task Force on Carbon Capture (August, 2010)* . A range of costs was provided for transport and storage facilities; for conservatism, the low ends of these ranges were used in this analysis as they contribute little to the total cost. Reported costs in $/tonne were converted to $/ton.

2. Tons of CO_2 controlled assumes 90% capture of all CO_2 emissions from the two turbines.

3. Pipeline costs are included in Table 6-2 for Acid Gas Stream, and it is assumed that the pipeline can handle both the turbine CO_2 and Acid Gas CO_2 streams.

4. Capital recovery factor based on 7% interest rate and 20 year equipment life.

Interest rate	7%
Equipent Life (yrs)	20

Table 6-2
Approximate Cost for Construction and Operation of a CCS System for Acid Gas Stream

Description	Cost	Basis
Capital Cost:		
AGI Compressor - Primary	$3,000,000	2.7 mmscfd, 7 psig to 2000 psig, 1000 hp, electric compression
AGI Compressor - Back Up	$3,000,000	2.7 mmscfd, 7 psig to 2000 psig, 1000 hp, electric compression
Installation- Compression	$4,000,000	Assume $2000/hp (includes power upgrade)
Dehydration Unit	$1,000,000	Past project cost for similar facility
AGI Pipeline - 6" Diameter	$29,000,000	50-mile pipeline 6 inch diameter (50 miles is location of nearest storage cavern). DOE/NETL calculation method (see below).
AGI Well (permitting, drilling, completion, etc.)	$10,000,000	Industry estimate
Total Capital Cost for Acid Gas Compression, Pipeline, and Well	**$50,000,000**	
Capital Recovery Factor[1]	0.0944	7% interest rate and 20 year equipment life
Annualized Capital Cost ($/yr)	**$4,719,646**	Total capital cost times capital recovery factor
Operating Cost:		
Power Cost, $/year	$489,925	1000 hp electric compressor and $0.075/kwh electricity cost
O&M Cost, $/year	$1,000,000	Past O&M estimate
Total Annual Operating Cost ($/yr)	**$1,489,925**	
Total Cost:		
Total Annual Cost ($/yr)	**$6,209,571**	Annualized capital cost plus annual operating cost
GHG Emissions Controlled (ton/yr)	69,452	From GHG Calculations in Appendix A
Cost Effectiveness ($/ton)	**$89**	Total Annual Cost/GHG Emissions Controlled

1. Capital recovery factor based on 7% interest rate and 20 year equipment life.

Interest rate:	7%
Equipent Life (yrs):	20

Capital Cost for Construction of CO2 Pipeline to Nearest Storage Cavern (Markham, TX area):

Length in miles (L):	50
Diameter in inches (D):	6

Component	**Cost**	**Cost Equation**[2]
Materials	$4,040,116	Materials = $64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)
Labor	$18,361,756	Labor = $341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)
Miscellaneous	$4,711,310	Misc. = $150,166 + $1.58 x L x (8,417 x D + 7,234)
Right-of-Way	<u>$2,043,037</u>	Right-of-Way = $48,037 + $1.20 x L x (577 x D + 29,788)
Total Cost of Pipeline	**$29,156,218**	

2: Pipeline cost equations are from: *Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs* , National Energy Technology Laboratory, U.S. Dept. of Energy, DOE/NETL-2010/1447, March 2010.

Section 7
Additional Impact Analysis

PSD regulations require an Additional Impacts Analysis for projects that are subject to PSD review. In 40 CFR 52.21(o), it states that:

> (1) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.
>
> (2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.

This section of the application addresses these requirements.

7.1 Visibility, Soils, and Vegetation

The proposed project will not result in a significant increase in any air contaminant other than GHGs; therefore, the project is not subject to PSD review for any other pollutant. GHGs themselves are not known to have any direct impact on visibility, soils, and vegetation other than their possible impact associated with global warming, which EPA has ruled does not need to be evaluated for GHG PSD permits. However, emissions of other air pollutants from the project could potentially impact these resources. Because the project increases for all other pollutants are insignificant, it is concluded that their impact on visibility, soils, and vegetation is also insignificant.

7.2 Associated Growth

The proposed project will not significantly affect residential, commercial, or industrial growth in the area. Only 2 to 3 new jobs are expected to be created by the addition of the proposed Cryo 3 facilities at the HCP. Even if these jobs were to be filled by individuals relocating to the area, it would result in a negligible impact on the existing infrastructure. Because these impacts will be negligible, the corresponding impact on air quality will also be negligible.

Appendix A

Emissions Calculations

Table A-1

Greenhouse Gas (GHG) Emissions from New Cryogenic Plant

Copano Gas Processing, LP, Houston Central Gas Plant

Colorado County, Texas

EPN	Description	Firing Rate (mmbtu/hr)	Firing Rate (mmbtu/yr)	CO2 (tpy*)	CH4 (tpy*)	N2O (tpy*)	Total CO2 Equivalent (tpy*)
HTR-3	Supplemental Gas Heater	25.00	15,000.0	875.9	0.02	0.002	876.7
HTR-4	Supplemental Gas Heater	25.00	15,000.0	875.9	0.02	0.002	876.7
RTO-3	RTO - Natural Gas Combustion	2.50	8,760.0	511.5	0.01	0.001	512.0
	RTO - Waste Gas Combustion			68,940.5			68,940.5
TURB-5	Solar Mars 100	114.59	1,003,808.4	58,614.5	1.1	0.1	58,671.9
TURB-6	Solar Mars 100	114.59	1,003,808.4	58,614.5	1.1	0.1	58,671.9
CRYO3 FUG	Fugitives	NA	NA	0.0	17.0	0.0	356.9
FLARE	LL Treater Flash Gas to Flare			835.5			835.5
Total				**189,268.1**	**19.2**	**0.2**	**189,742.2**
Contemporaneous Changes							
TURB-3	Solar Mars 100			58,819.1	1.1	0.1	58,876.7
TURB-4	Solar Mars 100			58,819.1	1.1	0.1	58,876.7
HTR-1	Supplement Gas Heater			875.9	0.0	0.0	876.7
HTR-2	Supplement Gas Heater			875.9	0.0	0.0	876.7
RTO-2	Regenerative Termal Oxidizer			58,005.3	0.2	0.002	58,009.5
STKBLR3	Steam Boiler No. 3			110,487.1	2.1	0.2	110,595.5
CRYO2 FUG	Fugitives			0.0	17.0	0.0	356.9

* Note all emission rates are in units of short tons.

** These two turbines will have a combined operating rate equal to one turbine operating at capacity year round.

Turbine Operating Schedule: 8760 hrs/yr
Heater Operating Schedule: 600 hrs/yr

Emission Rate (tpy) = Emission Factor (lb/mmbtu) x Firing Rate (mmbtu/yr) / 2000 lb/ton

Emission Factors:

Emission Factors from Tables C-1 & C-2 of Appendix A to 40 CFR Part 98 Subpart C

Pollutant	kg/mmBtu	lb/mmbtu
CO2	53.02	116.78
CH4	0.001	0.0022
N2O	0.0001	0.00022

Factors are for natural gas

CO2 Equivalents (ton/ton):

CO2	1.0
CH4	21.0
N2O	310.0

Table A-2
Regenerative Thermal Oxidizer Emissions
Copano Gas Processing, LP, Houston Central Gas Plant
Colorado County, Texas

Emission Source Type:	Regenerative Thermal Oxidizer
EPN:	RTO-3
Firing Rate (MMBtu/hr):	2.5
Operating Hours (hrs/yr):	8760
Waste Gas Flow from Cryo Unit 3 (scf/hr):	149,275
scf/mole:	387

Pilot Gas Emissions

Short term Rate

Firing Rate	Fuel Heating Value	Hours of Operation
(MMBtu/hr)	(Btu/scf)	(hrs/year)
2.5	1020	8760

Annual Rate

Firing Rate	Fuel Heating Value	Hours of Operation
(MMBtu/hr)	(Btu/scf)	(hrs/year)
1	1020	8760

Cryo Unit #3 (NEW) - Amine Still Flux Accumulator Acid Gas Analysis

Waste Stream								
Component	Inlet Flow to RTO						Outlet CO_2 to Atmos.	
	MW	Wt %	Mol%	Vol%	tpy	MMscf/yr	Carbon #	tpy
Methane	16.04	0.04%	0.1090%	0.1090%	29.54	1.4	1	81.0
Ethane	30.07	0.03%	0.0462%	0.0462%	23.45	0.6	2	68.7
Isobutane	58.12	0.00%	0.0000%	0.0000%	-	0.0	4	0.0
n-Butane	58.12	0.05%	0.0378%	0.0378%	37.11	0.5	4	112.4
Isopentane	72.15	0.00%	0.0000%	0.0000%	-	0.0	5	0.0
n-Pentane	72.15	0.02%	0.0118%	0.0118%	14.36	0.2	5	43.8
Carbon Dioxide	44.01	96.41%	91.9500%	91.9500%	68,388	1,202.4	1	68,388.1
Nitrogen	28.01	0.00%	0.0000%	0.0000%	-	0.0	0	0.0
H2S	34.08	0.00%	0.0001%	0.0001%	0.06	0.0	0	0.0
Propane	44.10	0.05%	0.0502%	0.0502%	37.39	0.7	3	111.9
C6+	86.18	0.06%	0.0302%	0.0302%	43.91	0.4	6	134.5
Water	18.00	3.33%	7.7688%	7.7688%	2,363.22	101.6	0	0.0
TOTAL		100.00%	100.00%	100.00%	70,937	1,308	NA	68,940

Note: Gas flow rate and composition used for GHG emissions differs from the worst case used for other compounds in the TCEQ permit, as the above scenario results in higher GHG emissions.

Table A-3
LL Treater Flash Gas Flaring
Copano Gas Processing, LP, Houston Central Gas Plant
Colorado County, Texas

Emission Source Type: Elevated Flare
EPN: FLARE
Flare Type: Air or Unassisted >1000
Operating Hours (hrs/yr): 8760
Sweep Gas Flow Rate: 830 (Basis: Process flow data)
scf/mole: 387

Cryo Unit #3 (NEW) - Amine Still Flux Accumulator Acid Gas Analysis

Waste Stream								
Component	Inlet Flow to RTO						Outlet CO_2 to Atmos.	
	MW	Wt %	Mol%	Vol%	tpy	MMscf/yr	Carbon #	tpy
Methane	16.04	25.06%	49.37%	49.3700%	74.39	3.6	1	204.1
Ethane	30.07	14.49%	15.23%	15.2300%	43.01	1.1	2	125.9
Isobutane	58.12	0.00%	0.00%	0.0000%	-	0.0	4	0.0
n-Butane	58.12	14.92%	8.12%	8.1155%	44.30	0.6	4	134.2
Isopentane	72.15	0.00%	0.00%	0.0000%	-	0.0	5	0.0
n-Pentane	72.15	8.33%	3.65%	3.6502%	24.74	0.3	5	75.4
Carbon Dioxide	44.01	4.77%	3.43%	3.4250%	14	0.2	1	14.2
Nitrogen	28.01	0.00%	0.0000%	0.0000%	-	0.0	0	0.0
H2S	34.08	0.00%	0.0001%	0.0001%	0.00	0.0	0	0.0
Propane	44.10	19.71%	14.13%	14.1300%	58.53	1.0	3	175.2
C6+	86.18	11.70%	4.29%	4.2927%	34.75	0.3	6	106.5
Water	18.00	1.02%	1.78%	1.7826%	3.01	0.1	0	0.0
TOTAL		100.00%	100.00%	100.00%	297	7	NA	835

Table A-4
Cryogenic Plant Equipment Leak Fugitives (EPN: CRYO3 FUG)
Copano Gas Processing, LP, Houston Central Gas Plant
Colorado County, Texas

Monitored Component Type	Service	[1]Oil & Gas Production Operations Fugitive Emission Factors	Total Component Count	28M Control Efficiencies (%)	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (TPY)	Controlled Emissions (lb/hr)	Controlled Emissions, all compounds (TPY)
Valves	Gas/Vapor	0.00992	1600	75%	15.87	69.52	3.97	17.38
	Light Liquid	0.0055	120	75%	0.66	2.89	0.17	0.72
	Heavy Liquid	0.0000185		0%				
Pumps	Gas Vapor	0.00529						
	Light Liquid	0.02866	14	75%	0.40	1.76	0.10	0.44
	Heavy Liquid	0.00113		0%				
Flanges	Gas/Vapor	0.00086	1400	30%	1.20	5.27	0.84	3.69
	Light Liquid	0.000243	140	30%	0.03	0.15	0.02	0.10
	Heavy Liquid	0.00000086		30%				
Compressors	Gas/Vapor	0.0194	8	75%	0.16	0.68	0.04	0.17
Relief Valves	Gas/Vapor	0.0194	24	75%	0.47	2.04	0.12	0.51
		Total:	***3306***		***18.79***	***82.31***	***5.26***	***23.02***

1) Emission factors are from TCEQ Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives October 2000 which refers to Oil and Gas Production Operations extracted from Table 2-4 of EPA-453/R-95-017

2) For Oil and Gas Production Operations, "Other" includes diaphragms, dump arms, hatches, instruments, meters, polished rods, and vents.

Sample Calculations:
Non-Monitored Component Count Emissions (lb/hr)=Emission Factor (lb/hr) * Non-Monitored Component Count

Speciated Emissions for Methane Calculation:

Inlet Gas Analysis					Component Emissions	
Compound	**Dry Basis Mole %**	**MW**	**lb/mol**	**Dry Basis Weight %**	**lb/hr**	**TPY**
Methane	87.40	16.043	1402.21	73.83%	3.88	16.99
Ethane	6.40	30.070	192.39	10.13%	0.53	2.33
Propane	2.54	44.097	111.79	5.89%	0.31	1.35
i-butane	0.497	58.124	28.89	1.52%	0.08	0.35
n-butane	0.66	58.124	38.25	2.01%	0.11	0.46
i-pentane	0.22	72.151	15.51	0.82%	0.04	0.19
n-pentane	0.15	72.151	10.82	0.57%	0.03	0.13
$C6^+$	0.17	86.117	14.64	0.77%	0.04	0.18
CO_2	1.84	44.010	80.85	4.26%		
N_2	0.14	28.013	3.84	0.20%		
H_2S	0.00	34.076	0.00	0.00%	0.00	0.00
Total:	100.00		1899.17	100.0%		
			Methane Total:	73.83%	3.88	**16.99**

**Use of inlet gas analysis is conservative as the compressors will be compressing residue gas.*

Appendix B

TCEQ Standard Permit Registration

Cielo Center, 1250 South Capital of Texas Highway, Building Three, Suite 200, Austin, Texas 78746, USA
T +1 512 347 7588 **F** +1 512 347 8243 **W** www.rpsgroup.com

Registration for Oil & Gas Standard Permit

Houston Central Gas Plant
Copano Processing, L.P.
Colorado County, Sheridan, Texas
CN601465255
RN101271419

May 2012

Table of Contents

List of Sections

List of Tables

List of Figures

List of Appendices

Section 1
Introduction

Copano Processing, L.P. (Copano) operates a gas processing plant and associated support facilities collectively referred to as Houston Central Gas Plant (HCP), which is located in Colorado County, Sheridan, Texas. The Houston Central Plant has a gas processing capacity of 1,100 million standard cubic feet per day per day (MMSCFD) and is a major source of NOx, CO and VOC emissions. Copano holds NSR Permits Nos. 56613, 17117, 17554, 96187 and various other permits by rule (PBRs) to authorize construction of existing emission sources. Federal Operating Permit (FOP) No. O-807 authorizes on-going operations. The company has decided to expand Houston Central Gas Plant operations by installing a new 400 MMSCFD cryogenic process train.   This train will consist of inlet gas mole sieve dehydrators, two supplemental heaters (HTR-3/HTR-4), a 400 MSCFD cryogenic process, liquid amine treating unit vents controlled by a new Regenerative Thermal Oxidizer (RTO-3) and elevated flare (FLARE), two (2) residue turbines (TURB-5 and TURB-6), an amine storage tank (TANK-3) and associated fugitive components (CRYO3 FUG).

As summarized in Table 1-1 and documented in this registration, HCP emissions qualify for the Non-Rule Oil and Gas Standard Permit under Title 30 Texas Administrative Code §116.620 (30 TAC §116.620). Please see the enclosed registration documentation for details.

This registration is organized into the following sections:

Section 1 presents the registration objectives, organization, and a summary of the proposed equipment and emissions.

Section 2 contains TCEQ administrative Form PI-1S, TCEQ Tables 4, 6, and 31.

Section 3 consists of an area map showing the gas plant location and a plot plan.

Section 4 presents a process description and process flow diagram.

Section 5 contains a discussion of the estimated emissions for the proposed equipment and a TCEQ Table 1(a) Emission Point Summary.

Section 6 includes information on the permit registration fee and a copy of the fee payment.

Section 7 addresses the standard permit general requirements as per 30 TAC §116.610 and §116.615.

Section 8 addresses the specific requirements of the Non-Rule Oil and Gas Standard Permit (30 TAC §116.620 – Installation and/or Modification of Oil and Gas Facilities).

Appendix A contains detailed operating data and emissions calculations.

Appendix B contains the NNSR/PSD applicability review for this standard permit registration in tabular format.

Appendix C contains the NAAQS evaluation and SCREEN3 modeling report.

Appendix D contains a copy of the claimed Non-Rule Oil and Gas Standard Permit, standard permit regulations and Permit by Rule 30 TAC §106.512.

Table 1-1

New Cryogenic Plant Emissions Summary
Copano Processing, LP, Houston Central Gas Plant

EPN	Emissions Source	VOC		NO_x		CO		SO_2		$PM/PM_{10}/PM_{2.5}$		Formaldehyde	
		lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
TURB-5	Solar Mars 100	0.80	3.50	4.13	18.07	6.98	30.57	0.39	1.71	0.76	3.31	0.08	0.36
TURB-6	Solar Mars 100	0.80	3.50	4.13	18.07	6.98	30.57	0.39	1.71	0.76	3.31	0.08	0.36
HTR-3	Gas Heater	12.38	3.71	2.45	0.74	2.06	0.62	0.01	<0.01	0.19	0.06	<0.01	<0.01
HTR-4	Gas Heater	12.38	3.71	2.45	0.74	2.06	0.62	0.01	<0.01	0.19	0.06	<0.01	<0.01
RTO-3	RTO	0.53	2.28	0.32	0.73	1.27	3.74	0.02	0.09	0.02	0.04		
TANK-3	Amine Tanks	0.01	0.01										
FLARE	Elevated Flare	0.61	2.66	0.19	0.84	0.38	1.68						
CRYO3 FUG	Fugitives	0.61	2.67										
Total		**28.11**	**22.05**	**13.66**	**39.18**	**19.72**	**67.79**	**0.83**	**3.51**	**1.91**	**6.78**	**0.17**	**0.71**

Section 2
Administrative Forms

This section contains the following TCEQ forms:

- Form PI-1S, Registration for Air Standard Permit
- TCEQ Table 4 – Combustion Units
- TCEQ Table 6 – Boilers and Heaters
- TCEQ Table 31 – Combustion Turbines

Texas Commission on Environmental Quality
Form PI-1S
Registrations for Air Standard Permit
(Page 1)

I. Registrant Information			
A. Is a TCEQ Core Data Form (TCEQ Form No. 10400) attached? Core Data Form required for Standard Permits 6004, 6006, 6007, 6008, and 6013.			☐ YES ☒ NO
Customer Reference Number (CN): CN601465255			
Regulated Entity Number (RN): RN101271419			
B. Company or Other Legal Customer Name (must be same as Core Data "Customer"): Copano Processing, LP			
Company Official Contact Name: Rex J. Prosser			
Title: Sr. Director, EH&S Corporate			
Mailing Address: 1200 Smith Street, Suite 2300			
City: Houston	State: Texas		ZIP Code: 77002
Phone No.: 713-621-9547	Fax No.: 713-737-9081		E-mail Address: rex.prosser@copano.com
C. Technical Contact Name: Rex J. Prosser			
Title: Sr. Director, EH&S Corporate			
Mailing Address: 1200 Smith Street, Suite 2300			
City: Houston	State: Texas		ZIP Code: 77002
Phone No.: 713-621-9547	Fax No.: 713-737-9081		E-mail Address: rex.prosser@copano.com
D. Facility Location Information (Street Address): 1650 County Road 255 South			
If no street address, provide clear driving directions to the site in writing:			
5 miles South on CR 255 of Alt. Hwy 90			
City: Sheridan	County: Colorado		ZIP Code: 77475
Latitude (nearest second): 29° 49' 41" N		Longitude (nearest second): 96° 40' 49" W	
II. Facility and Site Information			
A. Name and Type of Facility: Houston Central Gas Plant			☒ Permanent ☐ Portable
B. Type of Action:	☒ Initial Application ☐ Renewal	☐ Change to Registration	
	Registration No.:	☐ Expiration Date:	
C. List the Standard Permit Claimed: 6002			
Description: Non-Rule Oil and Gas Standard Permit			
D. Concrete Batch Plant Standard Permit: *(Check one)*			
☐ Central Mix ☐ Ready Mix ☐ Specialty Mix ☐ Enhanced Controls for Concrete Batch Plants			

II. Facility and Site Information ***(continued)***		
E. Proposed Start of Construction: 05/01/2013	Length of Time at the Site: 01/01/2014	
F. Is there a previous Standard Exemption or Permit by Rule for the facilities in this registration? *(Attach details regarding changes)*		☐ YES ☒ NO
If "YES," list Permit No.:		
G. Are there any other facilities at this site which are authorized by an air Standard Permit?		☒ YES ☐ NO
If "YES," list Permit No.: 96187, 101369		
H. Are there any other air preconstruction permits at this site?		☒ YES ☐ NO
If "YES," list Permit No.: 17117, 17554, 96187 and 56613		
Are there any other air preconstruction permits at this site that would be directly associated with this project?		☒ YES ☐ NO
If "YES," list Permit No.: 56613, 101369		
I. TCEQ Account Identification Number (if known): CR-0020-R		
J. Is this facility located at a site which is required to obtain a federal operating permit pursuant to 30 TAC Chapter 122?		☒ YES ☐ NO ☐ To Be Determined
K. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this Form PI-1S application is approved.		
☐ Application for an FOP	☐ FOP Significant Revision	☐ FOP Minor
☐ Operational Flexibility/Off-Permit Notification	☐ Streamlined Revision for GOP	
☒ To Be Determined	☐ None	
L. Identify the type(s) issued and/or FOP application(s) submitted/pending for the site. *(check all that apply)*		
☒ SOP	☐ GOP	☐ GOP Application/Revision Application: Submitted or Under APD Review
☐ SOP Application Review Application: Submitted or Under APD Review		☐ N/A
III. Fee Information		
A. Is a copy of the check or money order attached?		☒ YES ☐ NO
Check/Money Order/Transaction Number 8430		
Company name on Check: RPS		
Fee Amount: $900		

Texas Commission on Environmental Quality
Registrations for Air Standard Permit

PI-1S
(Page 3)

IV.	**Public Notice *(If* Applicable*)***	
A.	Is the plant located at a site contiguous or adjacent to the public works project?	☐ YES ☒ NO
B.	Name of Public Place:	
Physical Address:		
City:	County:	
C.	Small Business Classification:	☐ YES ☐ NO
D.	Concrete batch plants with enhanced controls, permanent rock crushers, and animal carcass incinerators shall place a copy of the technically complete application at the appropriate TCEQ regional office only.	
E.	Please furnish the names of the state legislators who represent the area where the facility site is located:	
State Senator:		
State Representative:		
F.	For Concrete Batch Plants, name of the County Judge for this facility site**:**	
County Judge:		
Mailing Address:		
City:	State:	ZIP Code:
G.	For Concrete Batch Plants, is the facility located in a municipality and/or extraterritorial jurisdiction of a municipality?	☐ YES ☐ NO
If "YES," list the name(s) of the Presiding Officer(s) for the municipality and/or extraterritorial jurisdiction:		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
V.	**Technical Information Including State and Federal Regulatory Requirements** ***Registrants must be in compliance with all applicable state and federal regulations and standards to claim a Standard Permit.***	
A.	Is confidential information submitted and properly marked with this registration?	☐ YES ☒ NO
B.	Is a process flow diagram and a process description attached?	☒ YES ☐ NO
C.	Is a plot plan attached?	☒ YES ☐ NO
D.	Are emissions data and calculations for this claim attached?	☒ YES ☐ NO
E.	Is information attached showing how the general requirements and applicability (30 TAC § 116.610 and 116.615) are met?	☒ YES ☐ NO
F.	Is information attached showing how the specific requirements are met?	☒ YES ☐ NO

VI. Signature Requirements
The signature below indicates that I have knowledge of the facts herein set forth and that the same are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA. I further state that I have read and understand TWC §§ 7.177 7.183, which defines ***Criminal Offenses*** for certain violations, including intentionally or knowingly making or causing to be made false material statements or representations in this application, and TWC §§ 7.187, pertaining to ***Criminal Penalties***.
Name: Rex J. Prosser *Print Full Name*
Signature:______________________________ *Original Signature Required*
Date:______________________________

VII. Copies of the Registration		
Copies must be sent as listed below. Processing delays will occur if copies are not sent as noted.		
Air Permits Initial Review Team (APIRT)	Regular, Certified, Priority Mail Mail Code 161, P.O. Box 13087, Austin, Texas 78711-3087 OR Hand Delivery, Overnight Mail Mail Code 161, 12100 Park 35 Circle, Building C, Third Floor, Room 300 W, Austin, Texas 78753 Note: The official application cannot be faxed to the TCEQ	Original Money Order or Check , a Copy of Form PI-1S and Core Data Form; all attachments
Revenue Section TCEQ	Regular, Certified, Priority Mail Mail Code 214, P.O. Box 13088, Austin, Texas 78711-3088 OR Hand Delivery, Overnight Mail Mail Code 214, 12100 Park 35 Circle, Building A, Third Floor, Austin, Texas 78753	Original Money Order or Check, a Copy of Form PI-1S, Core Date Form
Appropriate TCEQ Regional Office	To find your regional office address go to www.tceq.texas.gov.us/ or call (512) 239-1250	Copy of Form PI-1S, Core Data Form, and all attachments
Appropriate Local Air Pollution Control Program(s)	To find your local air pollution control programs go to www.tceq.texas.gov/nav/permits/air_permits.html or call (512) 239-1250	Copy of Form PI-1S, Core Data Form, and all attachments

TABLE 4

COMBUSTION UNITS

OPERATIONAL DATA	
Number from flow diagram: RTO-3	Model Number(if available): TBD
Name of device: Regenerative Thermal Oxidizer	Manufacturer TBD

CHARACTERISTICS OF INPUT

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Waste Material*	1. C1	1.71	3.85	5.98
	2. C2	0.10	1.34	2.53
	3. CO2	5,046	9,060	13,074
	4. N2	0.0	3.5	7.0
	5. C6	1.65	10.71	19.77

Gross Heating Value of Waste Material (Wet basis if applicable)	Btu/lb	Air Supplied for Waste Material	Minimum SCFM (70°F & 14.7 psia)	Maximum SCFM(70°F & 14.7 psia)
			0.0	1922

Waste Material of Contaminated Gas	Total Flow Rate lb/hr		Inlet Temperature °F	
	Minimum Expected	Design Maximum	Minimum Expected	Design Maximum
	0.0	13,200	100	120

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Fuel	1. C1	4.5	7.8	11.14
	2. C2	0.4	0.6	0.9
	3. C3	0.01	0.02	0.03
	4. CO2	0.12	0.21	0.29

Gross Heating Value of Fuel	Btu/lb	Air Supplied for Fuel	Minimum SCFM (70°F & 14.7 psia)	Maximum SCFM(70°F & 14.7 psia)

*Describe how waste material is introduced into combustion unit on an attached sheet. Supply drawings, dimensioned and to scale to show clearly the design and operation of the unit.

*Waste material stream taken from RTO-2 calculation.
*Fuel stream represented from average residue gas composition

TABLE 4
(continued)

COMBUSTION UNITS

CHARACTERISTICS OF OUTPUT				
	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Flue Gas Released	1. VOC			0.53
	2. NOx			0.32
	3. CO			1.27
	4. SO2			0.02
	5. PM/PM10/PM2.5			0.02

Temperature at Stack Exit °F	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
	Minimum Expected	Maximum Expected	Minimum Expected	Maximum Expected
1400		13,133		110

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing ft³	Chamber Velocity at Average Chamber Temperature ft/sec	Average Chamber Temperature °F
Average Residence Time sec	Exhaust Stack Height ft	Exhaust Stack Diameter ft

ADDITIONAL INFORMATION FOR CATALYTIC COMBUSTION UNITS		
Number and Type of Catalyst Elements	Catalyst Bed Velocity ft/sec	Max. Flow Rate per Catalytic Unit (Manufacturer's Specifications) Specify Units

Attach separate sheets as necessary providing a description of the combustion unit, including details regarding principle of operation and the basis for calculating its efficiency. Supply an assembly drawing, dimensioned and to scale, to show clearly the design and operation of the equipment. If the device has bypasses, safety valves, etc., specify when such bypasses are to be used and under what conditions. Submit explanations on control for temperature, air flow rates, fuel rates, and other operating variables.

TABLE 6

BOILERS AND HEATERS

Type of Device: HTR-3		Manufacturer: TBD	
Number from flow diagram:		Model Number: TBD	

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	C1 89.8 C2 4.4 IC4 0.85 NC4 0.85 CO2 3.9 N2 0.25	100	Average 408	Design Maximum
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units)	Average ____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
1.5 ft	30 ft	55	55	400	

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
NOx 2.45 lb/hr CO 2.06 lb/hr VOC 12.38 lb/hr PM 0.19 lb/hr SO2 0.01 lb/hr	

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

* Data from Htr-1/2 calculations and modeling representations

TABLE 6

BOILERS AND HEATERS

Type of Device: HTR-4	Manufacturer: TBD
Number from flow diagram:	Model Number: TBD

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
			Average	Design Maximum
Natural Gas	C1 89.8 C2 4.4 IC4 0.85 NC4 0.85 CO2 3.9 N2 0.25	100	408	
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units)	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
1.5 ft	30 ft	55	55	400	

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
NOx 2.45 lb/hr CO 2.06 lb/hr VOC 12.38 lb/hr PM 0.19 lb/hr SO2 0.01 lb/hr	

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

* Data from Htr-1/2 calculations and modeling representations

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) TURB-5

APPLICATION	CYCLE
____ Electric Generation ___ Base Load ___ Peaking X Gas Compression ____ Other (Specify) ____	X Simple Cycle ____ Regenerative Cycle ____ Cogeneration ____ Combined Cycle

Manufacturer Solar Turbines
Model No. Mars 100
Serial No. ____

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ____
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 15,000 HP (MW)(hp)
Proposed Site Operating Range 15,000 HP (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO ____ (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
___ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
___ Not Provided ____ Process Offgas ____ Ethane
___ Fuel Oil ____ Refinery Gas ____ Other (specify) ____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
X Lean Premix Combustors ____ Oxidation Catalyst ____ Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Table 31
COMBUSTION TURBINES

TURBINE DATA

Emission Point Number From Table 1(a) TURB-6

APPLICATION

____ Electric Generation
___ Base Load ___ Peaking
X Gas Compression
____ Other (Specify) ____

CYCLE

X Simple Cycle
____ Regenerative Cycle
____ Cogeneration
____ Combined Cycle

Manufacturer Solar Turbines
Model No. Mars 100
Serial No. ____

Model represented is based on:
X Preliminary Design ____ Contract Award
____ Other(specify) ____
See TNRCC Reg. VI, 116.116(a)

Manufacturer's Rated Output at Baseload, ISO 15,000 HP (MW)(hp)
Proposed Site Operating Range 15,000 HP (MW)(hp)
Manufacturer's Rated Heat Rate at Baseload, ISO ____ (Btu/k W-hr)

FUEL DATA

Primary Fuels:
X Natural Gas ____ Process Offgas ____ Landfill/Digester Gas
____ Fuel Oil ____ Refinery Gas ____ Other

Backup Fuels:
____ Not Provided ____ Process Offgas ____ Ethane
____ Fuel Oil ____ Refinery Gas ____ Other (specify) ____

Attach fuel anaylses, including maximum sulfur content, heating value (specify LHV or HHV) and mole percent of gaseous constituents.

EMISSIONS DATA

Attach manufacturer's information showing emissions of NOx, CO, VOC and PM for each proposed fuel at turbine loads and site ambient temperatures representative of the range of proposed operation. The information must be sufficient to determine maximum hourly and annual emission rates. Annual emissions may be based on a conservatively low approximation of site annual average temperature. Provide emissions in pounds per hour and except for PM, parts per million by volume at actual conditions and corrected to dry, 15% oxygen conditions.

Method of Emission Control:
X Lean Premix Combustors ____ Oxidation Catalyst ____ Water Injection ____ Other(specify)
____ Other Low-NOx Combustor ____ SCR Catalyst ____ Steam Injection ____

ADDITIONAL INFORMATION

On separate sheets attach the following:

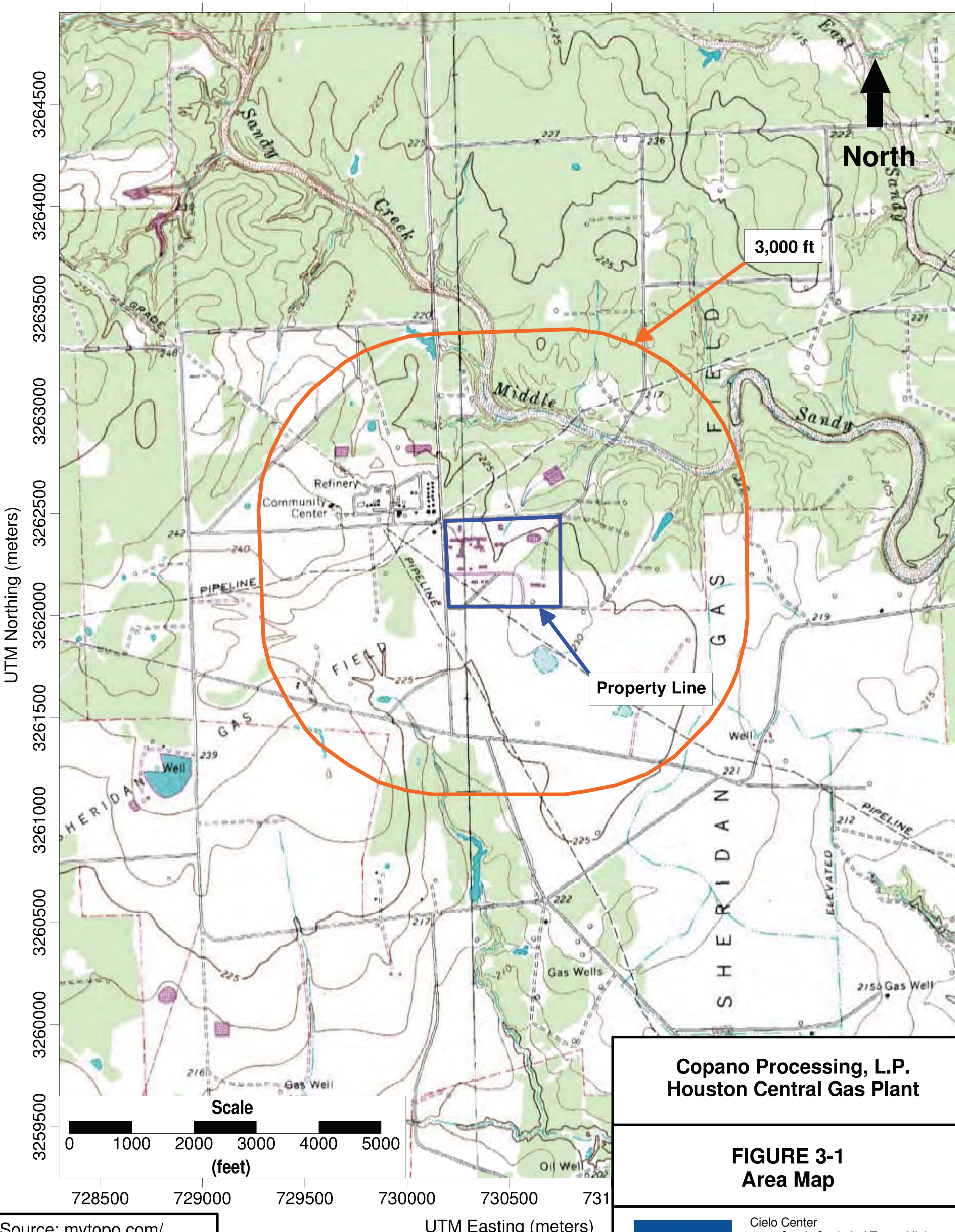
A. Details regarding principle of operation of emission controls. If add-on equipment is used, provide make and model and manufacturer's information. Example details include: controller input variables and operational algorithms for water or ammonia injection systems, combustion mode versus turbine load for variable mode combustors, etc.

B. Exhaust parameter information on Table 1(a).

C. If fired duct burners are used, information required on Table 6.

Section 3
Area Map and Plot Plan

An area map is included in Figure 3-1 and a plot plan of the HCP is provided in Figure 3-2.

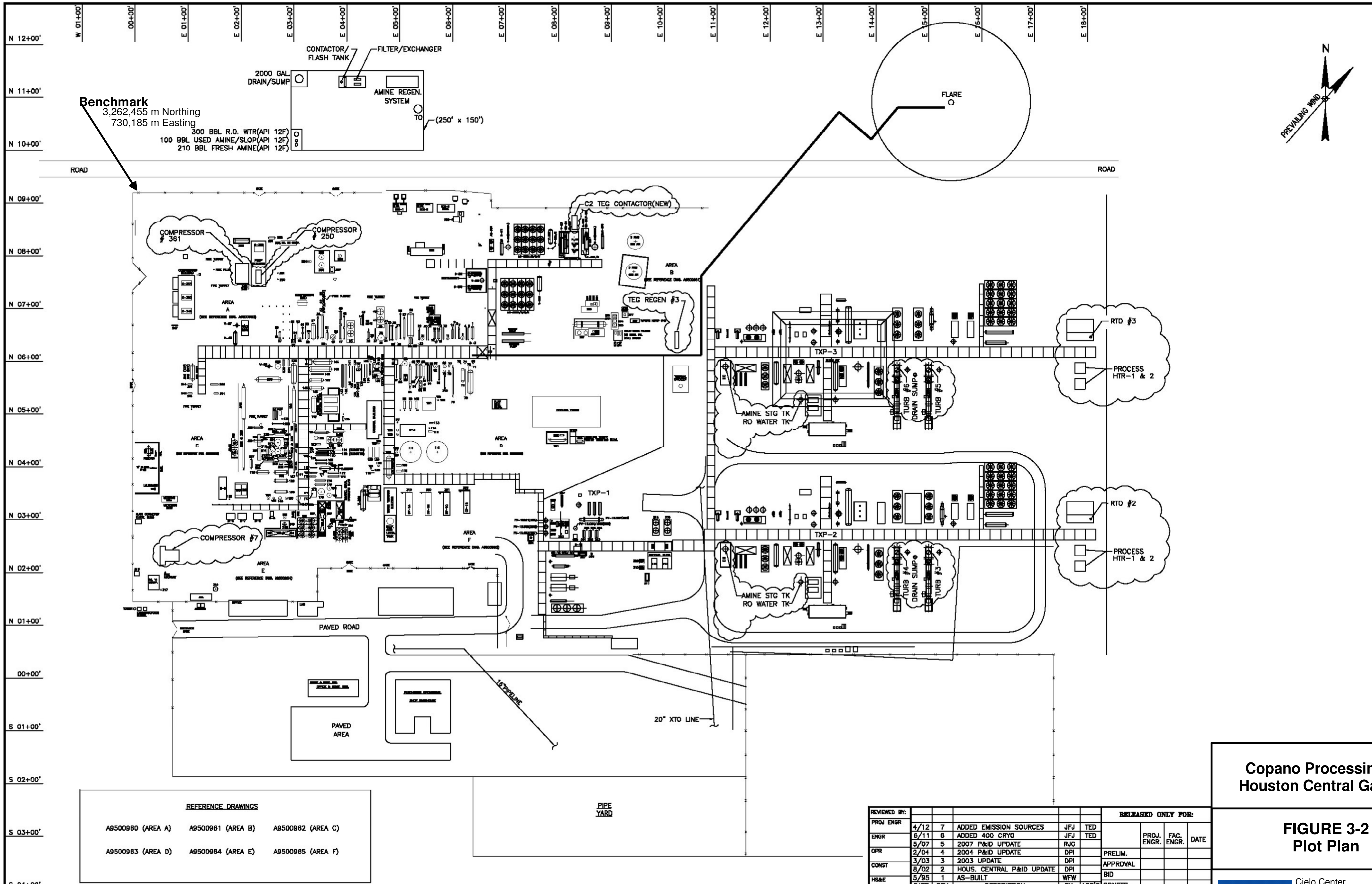


Source: mytopo.com/
Zone: 14
Coordinate Datum: NAD 83

Copano Processing, L.P.
Houston Central Gas Plant

FIGURE 3-1
Area Map

RPS
Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA



Copano Processing, L.P.
Houston Central Gas Plant

FIGURE 3-2
Plot Plan

RPS
Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA

Section 4
Process Description

4.1 Proposed New Equipment

Copano Processing, L.P. owns and operates the Houston Central Gas Plant (HCP), which is a natural gas processing, treatment, and fractionation facility that has a current nameplate capacity of 1,100 million standard cubic feet per day (MMSCFD). Copano is proposing to add an additional 400 MMSCFD cryogenic process, bringing the total plant capacity up to 1.5 billion standard cubic feet per day (BSCFD).

High pressure natural gas from the inlet pipeline will enter the plant, where it is first dehydrated through a molecular sieve dehydrator. After dehydration, the dry gas will then be processed through a cryogenic process removing the natural gas liquids (NGLs) from the gas. The NGLs are then sent through the site's existing fractionation columns. The residue gas from the cryogenic process will then be compressed and sent to sales. The compressors are driven by two new gas-fired combustion turbines. The liquids will be treated in a liquid amine treating unit (LL Treater), where CO_2 and trace amounts of H_2S will be removed from the NGLs. The acid gas (mostly CO_2 along with minor concentrations of H_2S and hydrocarbons) will then be routed to a new regenerative thermal oxidizer.

New project air emission sources consist of two supplemental gas-fired heaters (HTR-3 and HTR-4), a LL Treater controlled by a new Regenerative Thermal Oxidizer (RTO-3), an amine storage tank (TANK-3), two (2) Solar Mars 100 combustion turbines (TURB-5 and TURB-6) used for compression of the residue gas, fugitive piping components (CRYO3 FUG), and flaring of flash gas from the vent from the flasher in the LL Treater process. The flare (FLARE) has been previously authorized under TCEQ Standard Permit No. 101369. A process flow diagram for the proposed new equipment is shown in Figure 4-1.

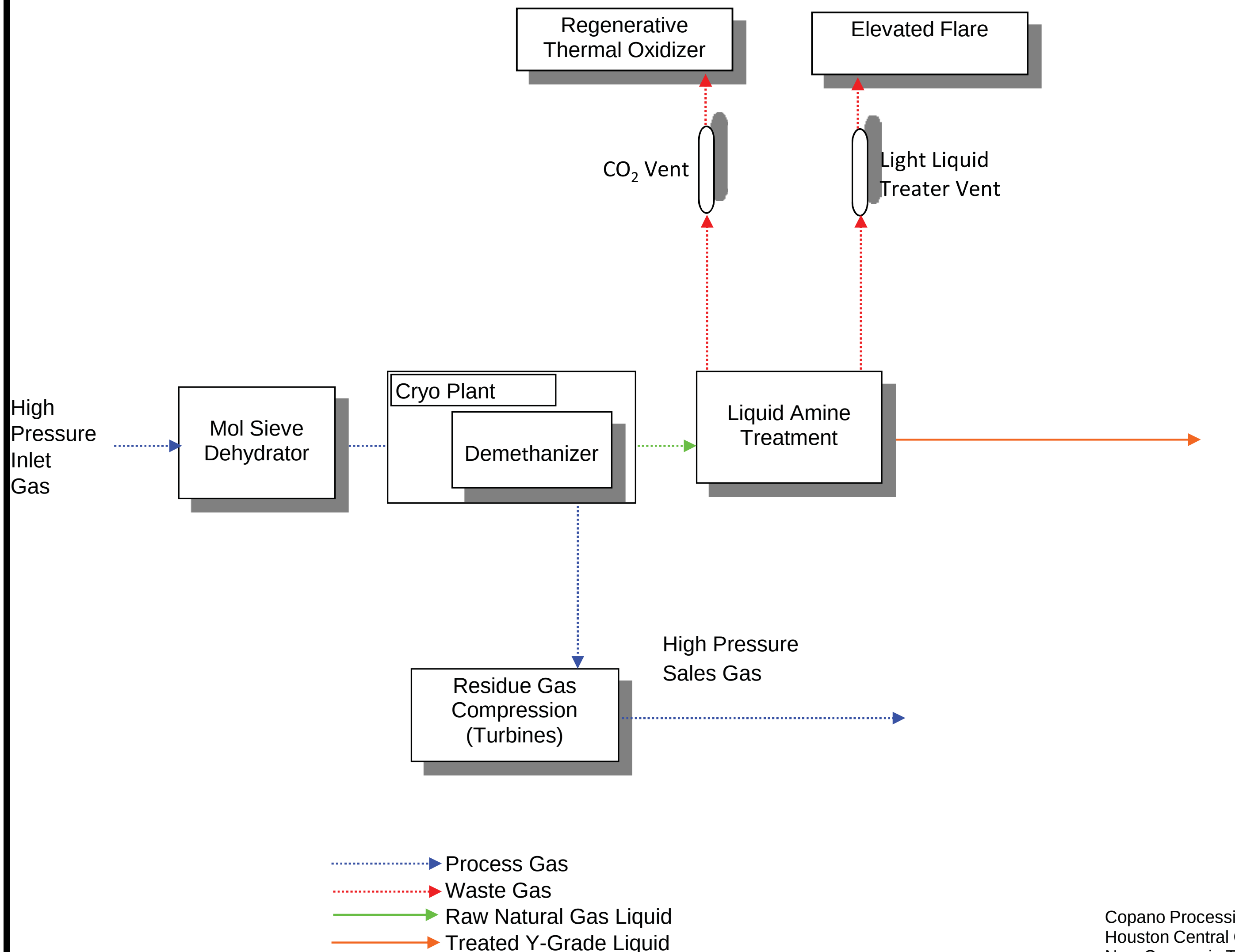
4.2 Existing Equipment

The existing HCP processes 1,100 MMSCFD of gas. Raw natural gas enters the plant from two high pressure sources and one low pressure source. The high pressure gas sources enter the plant at 1,000 psig. The low pressure gas source (approximately 7% of total gas inlet) from field production wells enters the plant, where it is compressed by the inlet gas compressors to

1,000 psig, then sent through an amine treating unit to remove CO2 and trace amounts of H2S. The acid gas from the amine treating unit (mostly CO2 along with minor concentrations of H2S and hydrocarbons) is routed to the site's existing regenerative thermal oxidizers. The treated gas is then dehydrated by the glycol dehydration system, which consists of an ethylene glycol treater and two triethylene glycol treaters. The overhead vapors from the dehydrators are routed back to a condenser unit. Uncondensed vapors from the condenser are vented to the plant's low pressure flare system. Emissions from the dehydration system intermediate flash tanks are recycled back into the plant fuel system.

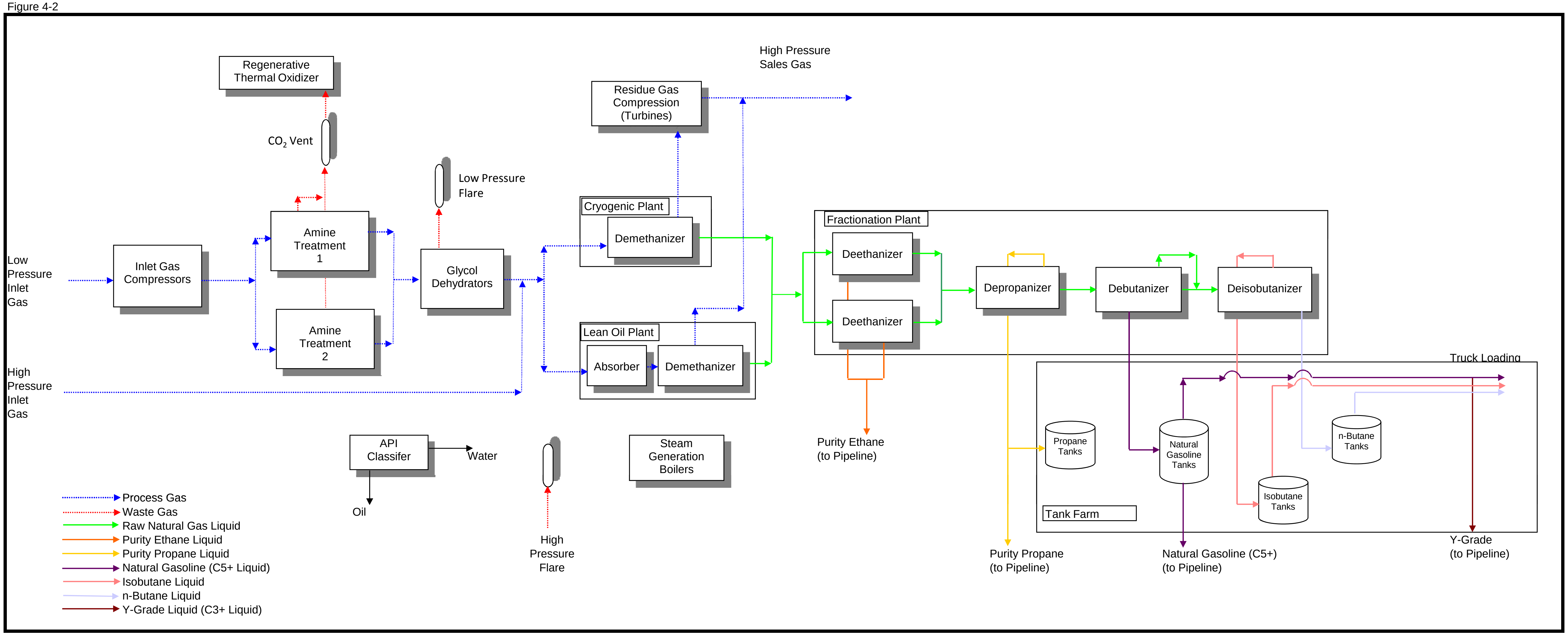
The dry, treated gas is then mixed with the two high pressure sources and sent on to a lean oil absorption process plant and a cryogenic process plant to process the natural gas and remove the NGLs. The residue gas is compressed and sent to sales. Some of the y-grade NGLs are then sent to the fractionation plant and separated into individual liquid products (ethane, propane, n-butane, isobutane, and natural gasoline (C5+)). The remaining y-grade and fractionated products are sent offsite via pipeline. The isobutene and n-butane are sent offsite via truck.

Steam generated from utility boilers is used for various processes in the plant, such as regenerating spent glycol in the dehydration system. A wastewater basin is used to collect wastewater runoff. This wastewater runoff is then treated with an API oil and water separator. There will be no change to these existing systems from this proposed expansion. A process flow diagram for the existing process is shown in Figure 4-2.



Copano Processing, L.P.
Houston Central Gas Plant
New Cryogenic Train
Figure 4-1 Process Flow Diagram

Copano Processing, L.P.
Houston Central Gas Plant
Existing Process Flow Diagram
Figure 4-2



Section 5
Emissions Summary

Emission factors and calculation methods are addressed in this section along with a TCEQ Table 1(a) – Emission Point Summary. Appendix A contains the emission factors and operations data used to calculate the hourly and annual emissions from the newly proposed emission sources at the Houston Central Plant.

5.1 Compressor Turbines

Compressor turbines TURB-5 and TURB-6 are Solar Mars 100 gas combustion turbines that will be fueled with natural gas and have a rated capacity of 15,000 HP each. All emissions are based on firing 100% natural gas. Emission factors for nitrogen oxides (NO_x), volatile organic compounds (VOC) and carbon monoxide (CO) are from manufacturer's specifications. The formaldehyde (CH2O), particulate (PM_{10} and $PM_{2.5}$) and sulfur dioxide (SO_2) emission factors used in the calculations are based on the AP-42 factors from Table 3.1.2 *Uncontrolled Emission Factors for Criteria Pollutants from Stationary Natural Gas Turbines* (5th edition, July 2000). Hourly emissions are based on the emission factors and the turbine operating at maximum capacity. Annual emissions are based on 8,760 hours/yr of operation. See Appendix A, Table A-1 for additional emission calculation details.

5.2 Supplemental Gas Heaters

Supplemental Gas Heater HTR-3 and HTR-4 emissions are based on firing 100% natural gas. Emission factors for nitrogen oxides (NO_x) , carbon monoxide (CO) , volatile organic compounds (VOC), formaldehyde, particulate matter (PM/PM_{10}/$PM_{2.5}$) and sulfur dioxide (SO_2) are used from AP-42 Tables 1.4-1, 1.4-2 and 1.4-3 from *Emission Factors for Natural Gas Combustion (July 1998).* Hourly emissions are based on the emission factors and the heaters operating at a maximum capacity of 25 MMBtu/hr. Annual emissions are based on a maximum of 600 hours/yr of operation for each heater. See Appendix A, Table A-2 for additional emission calculation details.

5.3 Amine Unit

The Amine Unit will produce an acid gas stream that will be controlled by a Regenerative Thermal Oxidizer (EPN RTO-3). EPN RTO-3 emissions are based on maximum acid gas VOC flows from the new amine treating system and required pilot/assist gas. Emissions from EPN RTO-3 are estimated using methods outlined in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers, October 2000*. The calculations employ a 99% VOC destruction efficiency. Emissions of NO_x and CO are quantified based on the emission factors for low BTU streams (less than 1,000 BTU/scf). Emissions for $PM/PM_{10}/PM_{2.5}$ were calculated based on the emission factors for small boilers/heaters. See Appendix A, Table A-3 for additional emission calculation details.

Copano's Amine Unit will also produce a flash gas vent stream that will be routed to a previously authorized elevated flare (EPN FLARE). Amine Unit flash gas emissions are calculated based on maximum flash gas flows and methods outlined in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers, October 2000*. Emissions of NO_x and CO were calculated based on the emission factors for low BTU streams. The calculations employ a 99% VOC destruction efficiency for material with three carbon atoms or less and a 98% VOC destruction efficiency for hydrocarbons with more than three carbon atoms. See Appendix A, Table A-5 for additional emission calculation details.

5.4 Fugitive Components

Process fugitive (equipment leak) emissions consist of VOC from the new piping components. The VOC emissions (EPN CRYO3 FUG) are estimated utilizing the TCEQ fugitive emission factors for the Oil and Gas Production Operations found in the TCEQ's *Equipment Leak Fugitives Technical Guidance* Document, October 2000 and by applying the control efficiencies from the 28M program as the site and new process train is subject to NSPS KKK. The annual fugitive emissions are based on 8,760 hours of service. See Appendix A, Table A-4 for emission calculations.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: May 2012	**Permit No.:** TBD	**Regulated Entity No.:** RN101271419
Area Name: Houston Central Gas Plant		**Customer Reference No.:** CN601465255

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND**	**(B) TPY**
TURB-5	TURB-5	Solar Turbine Mars 100	VOC	0.80	3.50
			NOx	4.13	18.07
			CO	6.98	30.57
			SO2	0.39	1.71
			$PM/PM_{10}/PM_{2.5}$	0.76	3.31
			Formaldehyde	0.08	0.36
TURB-6	TURB-6	Solar Turbine Mars 100	VOC	0.80	3.50
			NOx	4.13	18.07
			CO	6.98	30.57
			SO2	0.39	1.71
			$PM/PM_{10}/PM_{2.5}$	0.76	3.31
			Formaldehyde	0.08	0.36
HTR-3	HTR-3	Regeneration Gas Heater No. 3	VOC	12.38	3.71
			NOx	2.45	0.74
			CO	2.06	0.62
			SO2	0.01	<0.01
			$PM/PM_{10}/PM_{2.5}$	0.19	0.06
			Formaldehyde	<0.01	<0.01
HTR-4	HTR-4	Regeneration Gas Heater No. 4	VOC	12.38	3.71
			NOx	2.45	0.74
			CO	2.06	0.62
			SO2	0.01	<0.01
			$PM/PM_{10}/PM_{2.5}$	0.19	0.06
			Formaldehyde	<0.01	<0.01
RTO-3	RTO-3	Regenerative Thermal Oxidizer No. 3	VOC	0.53	2.28
			NOx	0.32	0.73
			CO	1.27	3.74
			SO2	0.02	0.09
			$PM/PM_{10}/PM_{2.5}$	0.02	0.04

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: May 2012	**Permit No.:** TBD	**Regulated Entity No.:** RN101271419
Area Name: Houston Central Gas Plant		**Customer Reference No.:** CN601465255

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND**	**(B) TPY**
FLARE	FLARE		VOC	0.61	2.66
			NOx	0.19	0.84
			CO	0.38	1.68
TANKS-3	TANKS-3	Storage Tanks	VOC	0.01	0.01
CRYO3 FUG	CRYO3 FUG	Process Fugitives	VOC	0.61	2.67

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: May 2012	**Permit No.:** TBD	**Regulated Entity No.:** RN101271419
Area Name: Houston Central Gas Plant		**Customer Reference No.:** CN601465255

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building Height	6. Height Above Ground	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	(Ft.)	(Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
TURB-5	TURB-5	Solar Turbine Mars 100	14	730635	3262370		50	4.9	94	400			
TURB-6	TURB-6	Solar Turbine Mars 100	14	730617	3262370		50	4.9	94	400			
HTR-3	HTR-3	Regeneration Gas Heater No. 3	14	730738	3262367		30	1.5	55	400			
HTR-4	HTR-4	Regeneration Gas Heater No. 4	14	730738	3262230		30	1.5	55	400			
RTO-3	RTO-3	Regenerative Thermal Oxidizer No. 3	14	730730	3262380		25	2.3	110	1600			
FLARE	FLARE	Elevated Flare	14	730646	3262538		245	0.33	3.28	1800			
TANKS-3	TANKS-3	Storage Tanks	14	730527	3262367		12	0.17	0.0033	Ambient			
CRYO3 FUG	CRYO3 FUG	Fugitives	14	730606	3262365		4	0.0033	0.0033	Ambient	660	160	

Section 6
Permit Registration Fee

In accordance with 30 TAC §116.614, a flat fee of $900 is required for each standard permit being registered. An electronic payment has been submitted to the TCEQ Financial Administration Division for the fee required for this air permit amendment. A copy of the fee payment is included in this section.

TRUE WATERMARK PAPER HOLD TO LIGHT TO VIEW HEAT SENSITIVE RED IMAGE DISAPPEARS WITH HEAT

8430

RPS
411 N. SAM HOUSTON PARKWAY E. STE. 400
HOUSTON, TX 77060

CHASE
JPMorgan Chase Bank, N.A.
www.Chase.com
32-61-1110

05/14/2012

PAY TO THE ORDER OF TCEQ $ *******900.00

NINE HUNDRED AND 00 /100 DOLLARS

TCEQ
P.O. Box 13088
Austin, TX 78711-3088

VOID AFTER 180 DAYS

AUTHORIZED SIGNATURE

MEMO

Security features. Details on back.

⑈008430⑈ ⑆111000614⑆ 732838123⑈

RPS

8430

TCEQ

REFERENCE	DESCRIPTION	AMOUNT
05142012	Permit-HOUCentralExpansio	900.00

RECEIVED
MAY 15 2012
TCEQ/Revenue Section

Section 7
General Requirements

30 TAC §116.610 and 116.615 specify the general standard permit registration requirements. This section addresses those requirements.

7.1 Applicability - 30 TAC § 116.610

The project will comply with all applicable components of 30 TAC §116.610 as follows:

§ 116.610(a)(1)	This project's emissions will comply with the emission limitations of §106.261/262. Refer to Appendix A, Table A-5 for this review.
§ 116.610(a)(2)	The construction of the project will commence prior to the effective date of a revision to 30 TAC 116, Subchapter F.
§ 116.610(a)(3)	The two natural gas turbines associated with this project comply with the provisions of the Federal Clean Air Act (FCAA), §111 (concerning New Source Performance Standards) as listed under 40 Code of Federal Regulations (CFR) Part 60, Subpart KKKK. Additionally, the new cryogenic process train and all associated equipment will comply with 40 CFR 60, Subpart KKK.
§ 116.610(a)(4)	The provisions of FCAA, §112 (concerning Hazardous Air Pollutants) as listed under 40 CFR Part 61, promulgated by the EPA, are not applicable to this project.
§ 116.610(a)(5)	The proposed turbines are not subject to the maximum achievable control technology standards as listed under 40 CFR Part 63 as the site is an area source for HAP emissions.
§ 116.610(a)(6)	This facility is not located within the Houston-Galveston-Brazoria ozone nonattainment area, therefore Chapter 101, Subchapter H, Division 3 (relating to Mass Emissions Cap and Trade Program) does not apply.
§ 116.610(b)	This project's emissions do not constitute a new major stationary source or major modification as defined in §116.12 of this title (relating to Nonattainment and Prevention of Significant Deterioration Review Definitions). Refer to Appendix B for this review.
§ 116.610(c)	This project will not circumvent by artificial limitations the requirements of §116.110.
§ 116.610(d)	This project does not involve an affected source; therefore, the requirements of Subchapter E do not apply.

7.2 General Conditions - 30 TAC § 116.615

The project will comply with all applicable general conditions of 30 TAC §116.615 to include compliance with all applicable rules and regulations of the commission adopted under Texas Health and Safety Code, Chapter 382, and with the intent of the Texas Clean Air Act (TCAA), including protection of health and property of the public; standard permit representations; construction progress; start-up notification; sampling requirements; equivalency of methods; recordkeeping; maintenance of emission controls; compliance with rules; and distance limitations, setbacks, and buffer zones.

Section 8
Specific Requirements

30 TAC §116.620 specifies the standard permit registration requirements for installation and/or modification of oil and gas facilities. This section addresses those requirements.

8.1 Installation and/or Modification of Oil and Gas Facilities - 30 TAC §116. 620

§116.620(a)(1)-(3)	This facility processes sweet gas and emits sulfur compounds at rates and in a manner that complies with §116.620(a)(1)-(3).
§116.620(a)(4)	See Section 8.2 for details satisfying §116.620(a)(4) in regards to §106.512 requirements.
§116.620(a)(5)	This project does not include a glycol dehydration unit; therefore, this requirement does not apply.
§116.620(a)(6)	The combustion turbines in this project shall emit NO_x at rates and in a manner that complies with §116.620(a)(6) as noted from the calculations representations in Appendix A.
§116.620(a)(7)-(11)	This facility is located more than 500 feet from the nearest off-plant receptor. Uncontrolled fugitives from this project do not exceed 25 tpy.
§116.620(a)(12)	Copano's elevated flare (EPN FLARE) will be designed and operated in accordance with 40 CFR 60.18, including minimum flare stream heating value and maximum flare stream exit velocity requirements.
§116.620(a)(13)	The facility is located in Colorado County which is not a designated nonattainment area; therefore, nonattainment permitting requirements are not applicable. This project is not considered a major modification for the federal Prevention of Significant Deterioration (PSD) program, and the facility is located in an area that is classified as attainment /unclassified for all criteria pollutants. Refer to Appendix B for PSD modification review.
§116.620(a)(14)	The combustion turbines are subject to 40 CFR 60 Subpart KKKK requirements. Additionally, the new cryogenic process train and all associated equipment will comply with 40 CFR 60, Subpart KKK.
§116.620(a)(15)	There are no applicable 40 CFR 61 requirements associated with this project.
§116.620(a)(16)	There are no applicable 40 CFR 63 requirements associated with this project.
§116.620(a)(17)	The increased emissions from this project will not cause or contribute to a violation of any National Ambient Air Quality Standard or regulation

property line standards as specified in Chapters 111, 112, or 113 as shown in the NAAQS table in Appendix C.

§116.620(a)(18) Fuel used at the site will not contain more than 10 grains total sulfur per 100 dscf of natural gas.

§116.620(b)(1) This requirement does not apply as there are no storage tanks on site which exceed 25,000 gallons or have uncontrolled VOC emissions greater than 10 tons per year associated with this project.

§116.620(b)(2) This requirement does not apply as there is no glycol dehydration system associated with this project.

116.620(c)(1)-(3) The facility is located more than 500 feet from the nearest off-plant receptor, and uncontrolled fugitive emissions are less than 25 tpy; therefore, these requirements do not apply.

§116.620(d)(1) This requirement does not apply as this project is not subject to a fugitive emissions control program.

§116.620(d)(2) This requirement does not apply since the facility does not use fuel with more than 1.5 grains of H_2S or 30 grains total sulfur per 100 dry standard cubic feet.

§116.620(d)(3) The requirement does not apply as this project does not include the use of a condenser as a control device.

§116.620(e) The facility will comply with the applicable requirements of this section.

8.2 Stationary Engines and Turbines - 30 TAC §106.512

§106.512(1) This registration application includes Table 31 forms in Section 2.

§106.512(2) This registration does not include any engines; therefore, this section does not apply.

§106.512(3) The two gas turbines are rated at greater than 500 hp, will operate at less than 3 gm/hp hr of NO_x and will be in compliance with NSPS Subpart KKKK.

§106.512(4) This registration does not include any engines or turbines rated less than 500 hp or used for temporary replacement purposes; therefore, this section does not apply.

§106.512(5) The combustion turbines at HCP fire natural gas containing no more than 10 grains total sulfur per 100 dry standard cubic feet.

§106.512(6) There will be no violations of any National Ambient Air Quality Standard (NAAQS) in the area of the proposed facility. Compliance is demonstrated using ambient sampling or dispersion modeling accomplished pursuant to guidance obtained from the executive director or another method allowed under item §106.512(6). Refer to Appendix C for a copy of the SCREEN3 model output report.

The model was run in the rural mode using the hourly NO_2 emission rates of 1.65 lb/hr for the proposed compressor turbines, 1.96 lb/hr for the proposed supplemental heaters, and 0.26 lb/hr for the proposed RTO. Concentrations were calculated for distances between thirty meters and five thousand meters for the sources. See Table C-1 for more details.

To demonstrate compliance with the 1-hour NO2 NAAQS standard, a SCREEN Impact maximum one-hour concentration for the sources was determined by the model. The one-hour concentration was converted to NO_2 using an NO_2/NO_X ratio of 0.40 (for the compressor turbine) and 0.8 for the heaters and RTO, per the applicable equation in paragraph 6(A) of PBR 106.512. The resulting final NO_2 concentration is 37.98 ug/m^3. A background concentration of 70 ug/m^3 ("Interim Screening Background Concentrations, July 22, 2010" under TCEQ Region 12) was added to the modeled concentration to obtain a total concentration of 107.98 ug/m^3. This concentration is less than the 1-hour NO_2 NAAQS of 188 ug/m^3; therefore, these emission source operations do not cause a violation of the NAAQS.

To demonstrate compliance with the annual NO_2 NAAQS standard, a SCREEN Impact maximum one-hour concentration for the sources was determined by the model. EPA's Screen3 model was also run for the existing Boiler 3N (the boiler installation was not included in September 4, 1998 annual background concentration). The one-hour concentration was converted to an annual average using a factor of 0.08 and then to NO_2 using an NO_2/NO_X ratio of 0.40, for the compressor turbines, 0.80 for the heaters and RTO per the applicable equation in paragraph 6(A) of PBR 106.512. The resulting final NO_2 concentration is 3.26 ug/m^3. A background concentration of 20 ug/m^3 ("Screening Background Concentrations, September 4, 2998 under TCEQ Region 12) was added to the modeled concentration to obtain a total concentration of 23.26 ug/m^3. This concentration is less than the annual NO_2 NAAQS of 100 ug/m^3; therefore, operations of these sources do not cause a violation of the NAAQS.

§106.512(7) This is not a standard permit registration for an electric generating unit; therefore, this section does not apply

Section 9
NNSR and PSD Applicability

Non-attainment New Source Review (NNSR) permitting is required for each non-attainment pollutant for which a modification of an existing major source will result in a significant net emissions increase. Prevention of Significant Deterioration (PSD) permitting is required for a modification of an existing major source for each attainment pollutant and other regulated pollutants (such as H_2S) for which the modification will result in a significant net emissions increase. Colorado County is designated attainment for all criteria pollutants; therefore, NNSR is not applicable for this project.

As shown in Appendix B, Table B-1, NNSR and PSD Applicability Determination, project emissions will result in permitted emissions increases that are less than the PSD netting thresholds of 40 tpy of NO_x, 100 tpy CO, 40 tpy of VOC, 25 tpy of PM, 15 tpy of PM_{10}, 10 tpy of $PM_{2.5}$ and 40 tpy of SO_2. Therefore, PSD is not applicable to these pollutants.

Appendix A

Emissions Calculations

Table A-1

Turbine Emissions (EPN: TURB-5 & TURB-6)

Copano Processsing, LP, Houston Central Gas Plant

Colorado County, Texas

<u>Turbine Model: Solar Mars 100</u>

UNIT MAX DESIGN HP	15,000
LHV, BTU/SCF	916
FUEL CONSUMPTION, BTU/BHP-HR	7639.3 Btu/hp-hr
Emissions = factor x MMBTU (fuel gas)	

	PERMIT HOURS	HP-HOURS	NOx	CO	NMVOC	PM10	SO2	Formaldehyde
EMISSION FACTORS, G/HP-HR			0.125	0.211	0.024	6.60E-03 (lb/MMBtu)	3.400E-03 (lb/MMBtu)	7.10E-04 (lb/MMBtu)
			LB/HR	LB/HR	LB/HR	LB/HR	LB/HR	LB/HR
			TONS/YR	TONS/YR	TONS/YR	TONS/YR	TONS/YR	TONS/YR
	8,760	131,400,000	**4.13**	**6.98**	**0.80**	**0.76**	**0.3896**	**0.08**
Horse Power Rating, hp 15,000			**18.07**	**30.57**	**3.50**	**3.31**	**1.71**	**0.36**

STACK VELOCITY DATA	HP-HOURS	SCFH FUEL	TEMP, °F	ACFH EXHAUST	DIAM. IN	VELOCITY FPS	HEIGHT Ft
	131,400,000	125,098	400	6,354,897	58.7	94.0	50.00

(1) Emission Factors for NOx,CO and VOC are from manufacturer's specifications. PM10, VOC, SO2 and Formaldehyde factors from AP-42 Table 3.1-2 and 3.1-3.

(2) SCFH Fuel = (Engine BHP x 7,639.3 BTU/BHP)/Fuel LHV

(3) ACFH, TEMP, & DIAM=Actual Data

(4) FPS=[6354897.46771759 ACFH/ 3600 sec/hr] / [(58.67 in / 12 in/ft)^2 * PI/4] = 94.0

Table A-2

Regen Gas Heater (EPN: HTR-3/HTR-4), Uncontrolled

Copano Processing, LP, Houston Central Gas Plant

25 MMBtu/hr Supplemental Gas Heater

EPN:	HTR-3/HTR-4		
Heater Description:	Regen Gas Heater		
Heater/Boiler Type:	Small Boiler (<100 MMBtu) Uncontrolled		
Annual Heater/Boiler Operating Hours (hrs/yr):	600		
Natural Gas Heating Value (Btu/scf):	1020		
Rated Duty/Heat Input (MMBtu/hr):	25		
Annual Fuel Usage (MMscf/yr):	14.71		
Rated Fuel Usage (scf/hr):	24510		
Control Efficiency (%):	0		
Pollutant	**Emission Factor, Small Boiler (<100 MMBtu) Uncontrolled (lb/MMSCF) [1]**	**Emissions**	
		(lb/hr)	**(tons/yr)**
NO_x	100.00	2.45	0.74
CO	84.00	2.06	0.62
NM/NE VOC	505.00	12.38	3.71
PM10	7.60	0.19	0.06
SO_2	0.60	0.01	0.004
Formaldehyde	0.075	0.002	0.001

[1]Based on AP-42, 5th ed. (July 1998) Tables 1.4-1,1.4-2 & 1.4-3, "Natural Gas Combustion".

Sample Calculations:

Short-Term Emissions (lb/hr)= (Emission Factor lb/MMscf) * (Rated Duty, MMBtu/hr) / (Heating Value Btu/scf)

Long-Term Emissions (tpy) = (Emission Rate lb/hr) * (Annual Operating Hours hrs/yr)/(2000 lb/ton)

Table A-3
Regenerative Thermal Oxidizer Emissions
Copano Gas Processing, LP, Houston Central Gas Plant
Colorado County, Texas

Emission Source Type:	Regenerative Thermal Oxidizer
EPN:	RTO-3
Firing Rate (MMBtu/hr):	2.5
Operating Hours (hrs/yr):	8760
Waste Gas Flow from Cryo Unit 3 (scf/hr):	125000

Pilot Gas Emissions

Short term Rate

			Emission Factors					Emission Rates				
Firing Rate (MMBtu/hr)	**Fuel Heating Value (Btu/scf)**	**Hours of Operation (hrs/year)**	**[1]NOx (lb/MMBtu)**	**[1]CO (lb/MMBtu)**	**[2]VOC (lb/MMScf)**	**[2]SO2 (lb/MMScf)**	**[2]PM_{10} (lb/MMScf)**	**NOx (lb/hr)**	**CO (lb/hr)**	**VOC (lb/hr)**	**PM_{10}**	**SO2 (lb/hr)**
2.5	1020	8760	0.100	0.2755	5.50	0.60	7.6	**0.25**	**0.69**	**0.013**	**0.019**	**0.0015**

Annual Rate

			Emission Factors					Emission Rates				
Firing Rate (MMBtu/hr)	**Fuel Heating Value (Btu/scf)**	**Hours of Operation (hrs/year)**	**[1]NOx (lb/MMBtu)**	**[1]CO (lb/MMBtu)**	**[2]VOC (lb/MMScf)**	**[2]SO2 (lb/MMScf)**	**[2]PM_{10} (lb/MMScf)**	**NOx (tpy)**	**CO (tpy)**	**VOC (tpy)**	**PM_{10}**	**SO2 (tpy)**
1	1020	8760	0.100	0.2755	5.50	0.60	7.6	**0.44**	**1.21**	**0.02**	**0.03**	**0.003**

(1) Emission factors for NOx and CO are based on TCEQ Guidance Document (October 2000) "Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers"

(2) Emission factors for VOC, SO2 and PM are based on AP-42, Fifth Edition, Tables 1.4-1 and 1.4-2 for commercial boilers and are scaled according to the fuel heating value.

Example Calculations:

2.5 MMBtu/hr x 1 scf/1020 Btu x 0.1 lb NOx/MMScf = 0.25 lb NOx/hr
1 MMBtu/hr x 1 scf/1020 Btu x 0.1 lb NOx/MMScf x 8760 hrs/year x 1 ton/2000 lbs = 0.44 tons NOx/year

Cryo Unit #3 (NEW) - Amine Still Flux Accumulator Acid Gas Analysis

	Waste Stream										
Component	Flow										
	MW	Wt %	Mol%	Vol%	lb/hr	tpy	scf/hr	MMscf/yr	mol/hr	scf/mole	mol/yr
Methane	16.04	0.01%	0.03%	0.03%	1.72	7.54	41.54	0.364	0.11	386.9	940.51
Ethane	30.07	0.001%	0.00%	0.00%	0.10	0.43	1.25	0.011	0.00	386.9	28.30
Isobutane	58.12	0.00%	0.00%	0.00%	-	-	-	-	0.00	386.9	0.00
n-Butane	58.12	0.07%	0.05%	0.05%	8.83	38.66	58.75	0.515	0.15	386.9	1330.24
Isopentane	72.15	0.00%	0.00%	0.00%	-	-	-	-	0.00	386.9	0.00
n-Pentane	72.15	0.13%	0.07%	0.07%	16.55	72.49	88.75	0.777	0.23	386.9	2009.51
Carbon Dioxide	44.01	99.59%	91.94%	91.94%	13,073.22	57,260.70	114,925.00	1,006.743	297.05	386.9	2602167.61
Nitrogen	28.01	0.00%	0.00%	0.00%	-	-	-	-	0.00	386.9	0.00
H2S	34.08	0.0001%	0.0001%	0.0001%	0.01	0.05	0.13	0.001	0.0003	386.9	2.83
Propane	44.10	0.05%	0.04%	0.04%	6.27	27.46	55.00	0.482	0.14	386.9	1245.33
C6+	86.18	0.15%	0.07%	0.07%	19.77	86.59	88.75	0.777	0.23	386.9	2009.51
SO2	64.00		-	-	-	-	-	-	-	386.9	-
TOTAL		100.00%	92.21%	92.21%	13,126.46	57,493.91	115,259.16	1,009.67	297.91		2,609,734

Component	**VOC EMISSIONS**			LHV	Net Heat Release			Emission Factors			**NOX, CO and PM_{10} EMISSIONS**					
	Efficiency	Emissions						lb/MMBTU		lb/MMscf	NOX		CO		$PM/PM_{10}/PM_{2.5}$	
	%	lb/hr	tpy	BTU/scf	BTU/scf	BTU/hr	MMBTU/yr	NOX	CO	PM	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Methane	99.0%	0.0172	0.0754	892	0	37,051	325	0.0641	0.5496	7.6	0.0024	0.0104	0.0204	0.0892	0.0003	0.0014
Ethane	99.0%	0.0010	0.0043	2,254	0	2,818	25	0.0641	0.5496	7.6	0.0002	0.0008	0.0015	0.0068	0.00001	0.00004
Isobutane	99.0%	0.0000	0.0000	2,923	-	-	-	0.0641	0.5496	7.6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Butane	99.0%	0.0883	0.3866	2,930	1	172,138	1,508	0.0641	0.5496	7.6	0.0110	0.0483	0.0946	0.4144	0.0004	0.0020
Isopentane	99.0%	0.0000	0.0000	3,602	-	-	-	0.0641	0.5496	7.6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
n-Pentane	99.0%	0.1655	0.7249	3,609	3	320,299	2,806	0.0641	0.5496	7.6	0.0205	0.0899	0.1760	0.7710	0.0007	0.0030
Carbon Dioxide	0%	13073.22	57260.70	-	-	-	-	0.0641	0.5496	7.6	0.0000	0.0000	0.0000	0.0000	-	-
Nitrogen	0%	0.0000	0.0000	-	-	-	-	0.0641	0.5496	7.6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
H2S	99.8%	0.00002	0.0001	596	0	75	1	0.0641	0.5496	7.6	0.0000	0.0000	0.0000	0.0002	0.0000	0.0000
Propane	99.0%	0.0627	0.2746	2,371	1	130,405	1,142	0.0641	0.5496	7.6	0.0084	0.0366	0.0717	0.3139	0.0004	0.0018
C6+	99.0%	0.1977	0.8659	4,376	3	388,370	3,402	0.0641	0.5496	7.6	0.0249	0.1090	0.2134	0.9349	0.0007	0.0030
SO2	-	0.0206	0.0904	-	-	-	-	0.0641	0.5496	7.6	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
TOTAL		0.5141	2.2520		8	1,051,155	9,208				0.0674	0.2951	0.5777	2.5304	0.0025	0.0111

TOTAL EMISSIONS		Annual Emissions
Component	lb/hr	tpy
VOC	0.53	2.28
NOx	0.32	0.73
CO	1.27	3.74
$PM/PM_{10}/PM_{2.5}$	0.02	0.04
SO_2	0.02	0.09

* Calculatons for waste gas stream based on October 2000, RG-109 Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers
Low BTU flare NOx/CO factors used. Small RTO should use 0.1 lb/MMBTU.

Table A-4
Equipment Leak Fugitives (EPN: CRYO3 FUG)
Copano Gas Processing, LP, Houston Central Gas Plant
Colorado County, Texas

Monitored Component Type	Service	[1]Oil & Gas Production Operations Fugitive Emission Factors	Total Component Count	28M Control Efficiencies (%)	Uncontrolled HC Emissions (lb/hr)	Uncontrolled HC Emissions (TPY)	Controlled HC Emissions (lb/hr)	Controlled HC Emissions (TPY)
Valves	Gas/Vapor	0.00992	1600	75%	15.87	69.52	3.97	17.38
	Light Liquid	0.0055	120	75%	0.66	2.89	0.17	0.72
	Heavy Liquid	0.0000185		0%				
Pumps	Gas Vapor	0.00529						
	Light Liquid	0.02866	14	75%	0.40	1.76	0.10	0.44
	Heavy Liquid	0.00113		0%				
Flanges	Gas/Vapor	0.00086	1400	30%	1.20	5.27	0.84	3.69
	Light Liquid	0.000243	140	30%	0.03	0.15	0.02	0.10
	Heavy Liquid	0.00000086		30%				
Compressors	Gas/Vapor	0.0194	8	75%	0.16	0.68	0.04	0.17
Relief Valves	Gas/Vapor	0.0194	24	75%	0.47	2.04	0.12	0.51
		Total:	***3306***		***18.79***	***82.31***	***5.26***	***23.02***

1) Emission factors are from TCEQ Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives October 2000 which refers to Oil and Gas Production Operations extracted from Table 2-4 of EPA-453/R-95-017

2) For Oil and Gas Production Operations, "Other" includes diaphragms, dump arms, hatches, instruments, meters, polished rods, and vents.

Sample Calculations:
Non-Monitored Component Count Emissions (lb/hr)=Emission Factor (lb/hr) * Non-Monitored Component Count

Inlet Gas Analysis					**Component Emissions**	
Compound	**Dry Basis Mole %**	**MW**	**lb/mol**	**Dry Basis Weight %**	**VOC lb/hr**	**VOC TPY**
Methane	87.40	16.043	1402.21	73.83%	3.88	16.99
Ethane	6.40	30.070	192.39	10.13%	0.53	2.33
Propane	2.54	44.097	111.79	5.89%	0.31	1.35
i-butane	0.497	58.124	28.89	1.52%	0.08	0.35
n-butane	0.66	58.124	38.25	2.01%	0.11	0.46
i-pentane	0.22	72.151	15.51	0.82%	0.04	0.19
n-pentane	0.15	72.151	10.82	0.57%	0.03	0.13
$C6^{+}$	0.17	86.117	14.64	0.77%	0.04	0.18
CO_2	1.84	44.010	80.85	4.26%		
N_2	0.14	28.013	3.84	0.20%		
H_2S	0.00	34.076	0.00	0.00%	0.00	0.00
Total:	100.00		1899.17	100.0%		
			VOC Total:	11.58%	0.61	2.67

**Use of inlet gas analysis is conservative as the compressors will be compressing residue gas.*

TABLE A-5
COPANO PROCESSING, LP
HOUSTON CENTRAL GAS PLANT
ELEVATED FLARE
Flash Gas Emissions
May 2012

Flare EPN: FLARE
Description of Unit: Elevated Flare
Flare Type: Air or Unassisted >1000 Btu/scf
Operating Hours (hrs/yr): 8760
Sweep Gas Flow (scf/hr): 829.63 (Basis: Process flow data)

Sweep Gas Stream								**VOC EMISSIONS**			LHV	Net Heat Release			Emission Factors		**NOX AND CO EMISSIONS**			
Component	Flow							Efficiency	Emissions						lb/MMBTU		NOX		CO	
	MW	Wt %	Mol%	Vol%	lb/hr	scf/hr	mol/hr	%	lb/hr	tpy	BTU/scf	BTU/scf	BTU/hr	MMBTU/yr	NOX	CO	lb/hr	tpy	lb/hr	tpy
Methane	16.04	25.06%	**49.37%**	49.37%	16.98	409.59	1.06	99.0%	0.1698	0.7439	892	440	365,351	3,200	0.138	0.2755	0.0504	0.2208	0.1007	0.4409
Ethane	30.07	14.49%	**15.23%**	15.23%	9.82	126.35	0.33	99.0%	0.0982	0.4301	2,254	343	284,797	2,495	0.138	0.2755	0.0393	0.1721	0.0785	0.3437
Propane	44.10	19.71%	**14.13%**	14.13%	13.36	117.23	0.30	99.0%	0.1336	0.5853	2,371	335	277,943	2,435	0.138	0.2755	0.0384	0.1680	0.0766	0.3354
Isobutane	58.12	0.00%	**0.00%**	0.00%	-	-	0.00	98.0%	0.0000	0.0000	2,923	-	-	-	0.138	0.2755	0.0000	0.0000	0.0000	0.0000
n-Butane	58.12	14.92%	**8.12%**	8.12%	10.11	67.33	0.17	98.0%	0.2023	0.8861	2,930	237.78	197,272	1,728	0.138	0.2755	0.0272	0.1192	0.0543	0.2380
Isopentane	72.15	0.00%	**0.00%**	0.00%	-	-	0.00	98.0%	0.0000	0.0000	3,602	-	-	-	0.138	0.2755	0.0000	0.0000	0.0000	0.0000
n-Pentane	72.15	8.33%	**3.65%**	3.65%	5.65	30.28	0.08	98.0%	0.1129	0.4947	3,609	132	109,291	957	0.138	0.2755	0.0151	0.0661	0.0301	0.1319
Carbon Dioxide	44.01	4.77%	**3.43%**	3.43%	3.23	28.41	0.07	0%	3.232	14.157	-	-	-	-	0.138	0.2755	0.0000	0.0000	0.0000	0.0000
Nitrogen	28.01	0.00%	**0.00%**	0.00%	-	-	0.00	0%	0.0000	0.0000	-	-	-	-	0.138	0.2755	0.0000	0.0000	0.0000	0.0000
H2S	34.08	0.00%	**0.00%**	0.00%	-	-	0.0000	98.0%	0.0000	0.0000	596	-	-	-	0.138	0.2755	0.0000	0.0000	0.0000	0.0000
Water	18.02	1.02%	**1.78%**	1.78%	0.69	14.79	0.04	0%	0.6886	3.0163	-	-	-	-	0.138	0.2755	0.0000	0.0000	0.0000	0.0000
n-Hexane	86.18	11.70%	**4.29%**	4.29%	7.93	35.61	0.09	98.0%	0.1587	0.6949	4,376	188	155,844	1,365	0.138	0.2755	0.0215	0.0942	0.0429	0.1881
Ucarsol AP-814	61.08	0.00%	0.00%	0.00%	0.00	0.00	0.00	98.0%	0.0000	0.0000	1,677	0	1	0	0.138	0.2755	0.0000	0.0000	0.0000	0.0000
TOTAL		100.00%	100.00%	100.00%	67.78	829.59	2.14		0.6075	2.6610		1,676	1,390,497	12,181			0.1919	0.8405	0.3831	1.6779

TOTAL EMISSIONS		
Component	lb/hr	tpy
VOC	1.22	2.66
NOX	0.38	0.84
CO	0.77	1.68

* Calculatons based on October 2000, RG-109 Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers

Table A-6
§106.261 and §106.262 Compliance Demonstration
Copano Processing, LP, Houston Central Gas Plant
Colorado County, Texas

Regenerative Thermal Oxidizer (EPN: RTO-3)	ft	K value
Distance to nearest off property receptor	>600	65

COMPOUND	Emissions (lb/hr)	Emissions (tons/yr)	PBR Section §106.	L Value mg/m3	Allowable Rate lb/hr	Allowable Rate TPY	Meets PBR?
n-Butane	0.09	0.39	261(a)(2)		6.00	10.00	YES
n-Pentane	0.17	0.72	262	350	5.38	5.00	YES
Propane	0.06	0.27	261(a)(2)		6.00	10.00	YES
C6+	0.20	0.87	261(a)(2)		6.00	10.00	YES

Fugitive Emissions (EPN: CRYO3 FUG)	ft	K value
Distance to nearest off property receptor	>600	65

COMPOUND	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tons/yr)	PBR Section §106.	L Value mg/m3	Allowable Rate lb/hr	Allowable Rate TPY	Meets PBR?
Propane	0.31	1.35	261(a)(2)		6.00	10.00	YES
i-butane	0.08	0.35	261(a)(2)		6.00	10.00	YES
n-butane	0.11	0.46	261(a)(2)		6.00	10.00	YES
i-pentane	0.04	0.19	262	350	5.38	5.00	YES
n-pentane	0.03	0.13	262	350	5.38	5.00	YES
C6+	0.04	0.18	261(a)(2)		6.00	10.00	YES

Turbine Emissions (EPN: TURB-5/TURB-6)	ft	K value
Distance to nearest off property receptor	>600	65

COMPOUND	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tons/yr)	PBR Section §106.	L Value mg/m3	Allowable Rate lb/hr	Allowable Rate TPY	Meets PBR?
Formaldehyde	0.08	0.36	261(a)(3)		1.00	-	YES

Flash Gas Emissions (EPN: FLARE)	ft	K value
Distance to nearest off property receptor	>600	65

COMPOUND	Emissions (lb/hr)	Emissions (tons/yr)	PBR Section §106.	L Value mg/m3	Allowable Rate lb/hr	Allowable Rate TPY	Meets PBR?
Propane	0.13	0.59	261(a)(2)		6.00	10.00	YES
n-Butane	0.20	0.89	261(a)(2)		6.00	10.00	YES
n-Pentane	0.11	0.49	262	350	5.38	5.00	YES
C6+	0.16	0.69	261(a)(2)		6.00	10.00	YES

PROJECT TOTALS	ft	K value
Distance to nearest off property receptor	>600	65

COMPOUND	Uncontrolled Emissions (lb/hr)	Uncontrolled Emissions (tons/yr)	PBR Section §106.	L Value mg/m3	Allowable Rate lb/hr	Allowable Rate TPY	Meets PBR?
Propane	0.51	2.21	261(a)(2)		6.00	10.00	YES
i-butane	0.08	0.35	261(a)(2)		6.00	10.00	YES
n-butane	0.31	1.35	261(a)(2)		6.00	10.00	YES
i-pentane	0.04	0.19	262	350	5.38	5.00	YES
n-pentane	0.31	1.35	262	350	5.38	5.00	YES
C6+	0.40	1.74	261(a)(2)		6.00	10.00	YES
formaldehyde	0.08	0.36	261(a)(3)		6.00	10.00	YES

Appendix B

NNSR and PSD Applicability Determination

Table B-1

New 400 MMSCFD Cryogenic Plant PSD Analysis
Copano Processsing, LP, Houston Central Gas Plant
Colorado County, Sheridan, Texas

EPN	Emission Point Description	Project VOC Emissions (tpy)			Project NOx Emissions (tpy)			Project CO Emissions (tpy)			Project SO_2 Emissions (tpy)			Project Total PM Emissions (tpy)			Project PM_{10} Emissions (tpy)			Project $PM_{2.5}$ Emissions (tpy)		
		Baseline	Proposed	Increase	Baseline	Proposed	Increase	Baseline	Proposed	Increase	Baseline	Proposed	Increase	Baseline	Proposed	Increase	Baseline	Proposed	Increase	Baseline	Proposed	Increase
TURB-5	Solar Turbine Mars 100	-	3.50	3.50	-	18.07	18.07	-	30.57	30.57	-	1.71	1.71	-	3.31	3.31	-	3.31	3.31	-	3.31	3.31
TURB-6	Solar Turbine Mars 100	-	3.50	3.50	-	18.07	18.07	-	30.57	30.57	-	1.71	1.71	-	3.31	3.31	-	3.31	3.31	-	3.31	3.31
HTR-3	Regeneration Gas Heater No. 3	-	3.71	3.71	-	0.74	0.74	-	0.62	0.62	-	0.004	0.004	-	0.06	0.06	-	0.06	0.06	-	0.06	0.06
HTR-4	Regeneration Gas Heater No. 4	-	3.71	3.71	-	0.74	0.74	-	0.62	0.62	-	0.004	0.004	-	0.06	0.06	-	0.06	0.06	-	0.06	0.06
RTO-3	Regenerative Thermal Oxidizer No.	-	2.28	2.28	-	0.73	0.73	-	3.74	3.74	-	0.09	0.09	-	0.04	0.04	-	0.04	0.04	-	0.04	0.04
TANK-3	Amine Tank	-	0.01	0.01	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FLARE	Elevated Flare	-	2.66	2.66	-	0.84	0.84	-	1.68	1.68	-	0.00	0.00	-	-	-	-	-	-	-	-	-
CRYO3 Fugitives	Fugitives	-	2.67	2.67	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Project Increase (tons)				***22.05***			***39.18***			***67.79***			***3.51***			***6.78***			***6.78***			***6.78***
Netting Threshold (tons)				***40***			***40***			***100***			***40***			***25***			***15***			***10***
Netting Required (Yes/No)				***No***			***No***			***No***			***No***			***No***			***No***			***No***
Significant Modification Threshold (tons)				***40***			***40***			***100***			***40***			***25***			***15***			***10***
Federal Review Required (Yes/No)				***No***			***No***			***No***			***No***			***No***			***No***			***No***

Appendix C

NAAQS Evaluation and SCREEN 3 Modeling Reports

Table C-1
Demonstration of NAAQS Compliance (106.512(6)(A))
Copano Processing, LP, Houston Central Gas Plant Expansion
Colorado County, Texas

EPN	Source Name	NO_x lb/hr	NO_x tpy	[1]NO_2/NO_x Ratio	NO_2 lb/hr	[2]SCREEN Impact Max 1-hour Concentration (ug/m^3)
Existing Sources:						
BLR-3N	Boiler 3N	2.15	9.46	0.40	0.86	2.80
New Sources to be Authorized:						
TURB-5	Solar Turbine Mars 100	4.13	18.11	0.40	1.65	0.88
TURB-6	Solar Turbine Mars 100	4.13	18.11	0.40	1.65	0.88
HTR-3	Supplemental Gas Heater	2.45	0.74	0.80	1.96	17.97
HTR-4	Supplemental Gas Heater	2.45	0.74	0.80	1.96	17.97
FLARE	Elevated Flare	0.19	0.84	0.80	0.15	0.35
RTO-3	Regenerative Thermal Oxidizer	0.317	0.733	0.80	0.25390	1.04
					New Source Total:	***39.09***

Annual Screen Model Results for NO2

New Source + BLR-3N Max 1-hour Concentration (ug/m^3)	[3]Multiplying Factor	[4]Annual Concentration (ug/m^3)	[5]Background Concentration (ug/m^3)	**[6]Total Concentration (ug/m^3)**	Annual NAAQS Standard (ug/m^3)	Compliant with NAAQS?
41.89	0.08	3.35	20	**23.35**	100	Yes

1-Hour Screen Model Results for NO2

New Source Max 1-hour Concentration (ug/m^3)	[7]Background Concentration (ug/m^3)	**[8]Total Concentration (ug/m^3)**	1-Hour NAAQS Standard (ug/m^3)	Compliant with NAAQS?
39.09	70	**109.09**	188	Yes

Notes:

1) NO_2/NO_x ratios taken from Figure 1: 30 TAC 106.512(6)(A).

2) SCREEN IMPACT (ug/m^3)

3) Multiplying factor taken from Table B-1 of the TCEQ "Air Quality Modeling Guidelines" document for Annual averaging time.

4) Annual Concentration = Max. 1-hr concentration x multiplying factor

5) Annual Background concentration for TCEQ Region 12 (Houston) is 20 ug/m^3.

6) Total Concentration = Annual Concentration + Background Concentration

7) 1-Hour Background concentration for TCEQ Region 12 (Houston) is 70 ug/m3.

8) Total Concentration = Hourly Concentration + Background Concentration

05/24/12
17:39:44

```
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Copano - Houston Central Gas Plant - TURB-5

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE            =        POINT
   EMISSION RATE (G/S)    =     0.207900
   STACK HEIGHT (M)       =      15.2400
   STK INSIDE DIAM (M)    =       1.4905
   STK EXIT VELOCITY (M/S)=      28.6511
   STK GAS EXIT TEMP (K)  =     477.5944
   AMBIENT AIR TEMP (K)   =     293.1500
   RECEPTOR HEIGHT (M)    =       0.0000
   URBAN/RURAL OPTION     =        RURAL
   BUILDING HEIGHT (M)    =       0.0000
   MIN HORIZ BLDG DIM (M) =       0.0000
   MAX HORIZ BLDG DIM (M) =       0.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX =   60.263 M**4/S**3;  MOM. FLUX =  279.845 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

  DIST     CONC              U10M   USTK  MIX HT   PLUME   SIGMA   SIGMA
   (M)   (UG/M**3)   STAB   (M/S)  (M/S)    (M)    HT (M)   Y (M)   Z (M)  DWASH
-------  ----------  ----   -----  -----  ------   ------  ------  ------  -----
    36.  0.2782E-07    6     1.0     1.3 10000.0   104.77   15.57   15.52    NO
   100.  0.2214E-01    5     1.0     1.2 10000.0   126.20   32.29   31.90    NO
   200.  0.2548E-01    5     1.0     1.2 10000.0   126.20   33.77   32.31    NO
   300.  0.2181        3    10.0    10.4  3200.0    58.65   35.15   21.74    NO
   400.  0.5569        3    10.0    10.4  3200.0    58.65   45.61   28.04    NO
   500.  0.7634        3    10.0    10.4  3200.0    58.65   55.83   34.19    NO
   600.  0.8588        4    20.0    21.3  6400.0    36.03   43.13   22.04    NO
   700.  0.8793        4    20.0    21.3  6400.0    36.03   49.56   24.79    NO
   800.  0.8557        4    20.0    21.3  6400.0    36.03   55.90   27.46    NO
   900.  0.8106        4    20.0    21.3  6400.0    36.03   62.18   30.08    NO
  1000.  0.7667        4    15.0    16.0  4800.0    43.57   68.61   33.10    NO
  1100.  0.7301        4    15.0    16.0  4800.0    43.57   74.75   35.07    NO
  1200.  0.6920        4    15.0    16.0  4800.0    43.57   80.85   36.99    NO
  1300.  0.6540        4    15.0    16.0  4800.0    43.57   86.90   38.85    NO
  1400.  0.6174        4    15.0    16.0  4800.0    43.57   92.91   40.67    NO
  1500.  0.5950        4    10.0    10.7  3200.0    57.74   99.29   43.40    NO
  1600.  0.5770        4    10.0    10.7  3200.0    57.74  105.20   45.10    NO
  1700.  0.5581        4    10.0    10.7  3200.0    57.74  111.07   46.77    NO
  1800.  0.5389        4    10.0    10.7  3200.0    57.74  116.92   48.41    NO
  1900.  0.5197        4    10.0    10.7  3200.0    57.74  122.73   50.02    NO
  2000.  0.5009        4    10.0    10.7  3200.0    57.74  128.52   51.60    NO
  2100.  0.4825        4    10.0    10.7  3200.0    57.74  134.28   53.16    NO
  2200.  0.4667        4     8.0     8.5  2560.0    68.37  140.31   55.44    NO
  2300.  0.4543        4     8.0     8.5  2560.0    68.37  146.00   56.94    NO
  2400.  0.4418        4     8.0     8.5  2560.0    68.37  151.67   58.41    NO
```

```
  2500.  0.4295        4     8.0     8.5  2560.0   68.37  157.32   59.86    NO
  2600.  0.4174        4     8.0     8.5  2560.0   68.37  162.95   61.29    NO
  2700.  0.4252        5     2.0     2.3 10000.0  103.31  128.08   47.05    NO
  2800.  0.4357        5     2.0     2.3 10000.0  103.31  132.20   47.76    NO
  2900.  0.4454        5     2.0     2.3 10000.0  103.31  136.31   48.46    NO
  3000.  0.4544        5     2.0     2.3 10000.0  103.31  140.41   49.15    NO
  3500.  0.4992        5     1.5     1.7 10000.0  112.17  161.15   53.79    NO
  4000.  0.5405        5     1.0     1.2 10000.0  126.20  181.84   59.01    NO
  4500.  0.5640        5     1.0     1.2 10000.0  126.20  201.59   61.60    NO
  5000.  0.5799        5     1.0     1.2 10000.0  126.20  221.15   64.10    NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND    36. M:
   685.  0.8798        4    20.0    21.3  6400.0   36.03   48.67   24.41    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** INVERSION BREAK-UP FUMIGATION CALC. ***
  CONC (UG/M**3)   =    1.205
  DIST TO MAX (M)  =  5251.61

     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC    DIST TO   TERRAIN
  PROCEDURE         (UG/M**3)    MAX (M)    HT (M)
--------------     -----------   -------   -------
SIMPLE TERRAIN      0.8798         685.        0.

INV BREAKUP FUMI     1.205        5252.       --
```

05/24/12
17:55:21

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

Copano - Houston Central Gas Plant - TURB-6

SIMPLE TERRAIN INPUTS:

SOURCE TYPE	=	POINT
EMISSION RATE (G/S)	=	0.207900
STACK HEIGHT (M)	=	15.2400
STK INSIDE DIAM (M)	=	1.4905
STK EXIT VELOCITY (M/S)	=	28.6512
STK GAS EXIT TEMP (K)	=	477.5944
AMBIENT AIR TEMP (K)	=	293.1500
RECEPTOR HEIGHT (M)	=	0.0000
URBAN/RURAL OPTION	=	RURAL
BUILDING HEIGHT (M)	=	0.0000
MIN HORIZ BLDG DIM (M)	=	0.0000
MAX HORIZ BLDG DIM (M)	=	0.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

BUOY. FLUX = 60.263 M**4/S**3; MOM. FLUX = 279.847 M**4/S**2.

*** FULL METEOROLOGY ***

****
*** SCREEN AUTOMATED DISTANCES ***
****

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
37.	0.8980E-07	6	1.0	1.3	10000.0	104.77	16.01	15.96	NO
100.	0.2214E-01	5	1.0	1.2	10000.0	126.20	32.29	31.90	NO
200.	0.2548E-01	5	1.0	1.2	10000.0	126.20	33.77	32.31	NO
300.	0.2181	3	10.0	10.4	3200.0	58.65	35.15	21.74	NO
400.	0.5569	3	10.0	10.4	3200.0	58.65	45.61	28.04	NO
500.	0.7634	3	10.0	10.4	3200.0	58.65	55.83	34.19	NO
600.	0.8588	4	20.0	21.3	6400.0	36.03	43.13	22.04	NO
700.	0.8793	4	20.0	21.3	6400.0	36.03	49.56	24.79	NO
800.	0.8557	4	20.0	21.3	6400.0	36.03	55.90	27.46	NO
900.	0.8106	4	20.0	21.3	6400.0	36.03	62.18	30.08	NO
1000.	0.7667	4	15.0	16.0	4800.0	43.57	68.61	33.10	NO
1100.	0.7301	4	15.0	16.0	4800.0	43.57	74.75	35.07	NO
1200.	0.6920	4	15.0	16.0	4800.0	43.57	80.85	36.99	NO
1300.	0.6540	4	15.0	16.0	4800.0	43.57	86.90	38.85	NO
1400.	0.6174	4	15.0	16.0	4800.0	43.57	92.91	40.67	NO
1500.	0.5950	4	10.0	10.7	3200.0	57.74	99.29	43.40	NO
1600.	0.5770	4	10.0	10.7	3200.0	57.74	105.20	45.10	NO
1700.	0.5581	4	10.0	10.7	3200.0	57.74	111.07	46.77	NO
1800.	0.5389	4	10.0	10.7	3200.0	57.74	116.92	48.41	NO
1900.	0.5197	4	10.0	10.7	3200.0	57.74	122.73	50.02	NO
2000.	0.5009	4	10.0	10.7	3200.0	57.74	128.52	51.60	NO
2100.	0.4825	4	10.0	10.7	3200.0	57.74	134.28	53.16	NO
2200.	0.4667	4	8.0	8.5	2560.0	68.37	140.31	55.44	NO
2300.	0.4543	4	8.0	8.5	2560.0	68.37	146.00	56.94	NO
2400.	0.4418	4	8.0	8.5	2560.0	68.37	151.67	58.41	NO

```
   2500.  0.4295        4     8.0     8.5  2560.0   68.37  157.32   59.86    NO
   2600.  0.4174        4     8.0     8.5  2560.0   68.37  162.95   61.29    NO
   2700.  0.4252        5     2.0     2.3 10000.0  103.31  128.08   47.05    NO
   2800.  0.4357        5     2.0     2.3 10000.0  103.31  132.20   47.76    NO
   2900.  0.4454        5     2.0     2.3 10000.0  103.31  136.31   48.46    NO
   3000.  0.4544        5     2.0     2.3 10000.0  103.31  140.41   49.15    NO
   3500.  0.4992        5     1.5     1.7 10000.0  112.17  161.15   53.79    NO
   4000.  0.5405        5     1.0     1.2 10000.0  126.20  181.84   59.01    NO
   4500.  0.5640        5     1.0     1.2 10000.0  126.20  201.59   61.60    NO
   5000.  0.5799        5     1.0     1.2 10000.0  126.20  221.15   64.10    NO

 MAXIMUM 1-HR CONCENTRATION AT OR BEYOND    37. M:
    685.  0.8798        4    20.0    21.3  6400.0   36.03   48.67   24.41    NO

  DWASH=   MEANS NO CALC MADE (CONC = 0.0)
  DWASH=NO MEANS NO BUILDING DOWNWASH USED
  DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
  DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
  DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

  *** INVERSION BREAK-UP FUMIGATION CALC. ***
   CONC (UG/M**3)   =    1.205
   DIST TO MAX (M)  =  5251.62

      ***************************************
      *** SUMMARY OF SCREEN MODEL RESULTS ***
      ***************************************

  CALCULATION          MAX CONC     DIST TO    TERRAIN
   PROCEDURE          (UG/M**3)     MAX (M)     HT (M)
 --------------      -----------    -------    -------
 SIMPLE TERRAIN      0.8798            685.         0.

 INV BREAKUP FUMI     1.205           5252.        --
```

03/26/12
12:14:30

```
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Copano - Houston Central Gas Plant - HTR-3

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =     0.247000
   STACK HEIGHT (M)         =       9.1440
   STK INSIDE DIAM (M)      =       0.4572
   STK EXIT VELOCITY (M/S)=        16.8371
   STK GAS EXIT TEMP (K)    =     477.5944
   AMBIENT AIR TEMP (K)     =     293.1500
   RECEPTOR HEIGHT (M)      =       0.0000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =       0.0000
   MIN HORIZ BLDG DIM (M) =         0.0000
   MAX HORIZ BLDG DIM (M) =         0.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX =    3.332 M**4/S**3;  MOM. FLUX =    9.093 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***
```

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
66.	5.047	2	5.0	5.0	1600.0	19.71	13.35	7.52	NO
100.	14.74	2	5.0	5.0	1600.0	19.71	19.49	11.01	NO
200.	17.91	3	5.0	5.0	1600.0	19.71	23.81	14.35	NO
300.	15.96	3	3.0	3.0	960.0	26.76	34.66	20.94	NO
400.	15.44	4	4.5	4.5	1440.0	20.89	29.64	15.63	NO
500.	14.29	4	3.5	3.5	1120.0	24.24	36.40	18.80	NO
600.	13.16	4	3.0	3.0	960.0	26.76	43.01	21.80	NO
700.	12.14	4	2.5	2.5	800.0	30.28	49.56	24.78	NO
800.	11.15	4	2.5	2.5	800.0	30.28	55.90	27.45	NO
900.	10.47	4	2.0	2.0	640.0	35.56	62.34	30.42	NO
1000.	9.722	4	2.0	2.0	640.0	35.56	68.54	32.97	NO
1100.	9.027	4	1.5	1.5	480.0	44.37	74.99	35.58	NO
1200.	8.559	4	1.5	1.5	480.0	44.37	81.07	37.47	NO
1300.	8.096	4	1.5	1.5	480.0	44.37	87.10	39.31	NO
1400.	7.649	4	1.5	1.5	480.0	44.37	93.10	41.11	NO
1500.	7.471	5	1.0	1.0	10000.0	53.55	74.78	30.68	NO
1600.	7.539	5	1.0	1.0	10000.0	53.55	79.17	31.74	NO
1700.	7.562	5	1.0	1.0	10000.0	53.55	83.54	32.78	NO
1800.	7.675	6	1.0	1.0	10000.0	45.99	58.82	22.81	NO
1900.	7.929	6	1.0	1.0	10000.0	45.99	61.68	23.43	NO
2000.	8.142	6	1.0	1.0	10000.0	45.99	64.54	24.05	NO
2100.	8.245	6	1.0	1.0	10000.0	45.99	67.38	24.58	NO
2200.	8.322	6	1.0	1.0	10000.0	45.99	70.22	25.10	NO
2300.	8.377	6	1.0	1.0	10000.0	45.99	73.04	25.60	NO
2400.	8.411	6	1.0	1.0	10000.0	45.99	75.85	26.10	NO

```
  2500.   8.428        6     1.0      1.0 10000.0   45.99   78.66   26.60    NO
  2600.   8.429        6     1.0      1.0 10000.0   45.99   81.45   27.08    NO
  2700.   8.417        6     1.0      1.0 10000.0   45.99   84.23   27.56    NO
  2800.   8.392        6     1.0      1.0 10000.0   45.99   87.00   28.03    NO
  2900.   8.358        6     1.0      1.0 10000.0   45.99   89.77   28.50    NO
  3000.   8.314        6     1.0      1.0 10000.0   45.99   92.52   28.96    NO
  3500.   7.896        6     1.0      1.0 10000.0   45.99  106.18   30.83    NO
  4000.   7.449        6     1.0      1.0 10000.0   45.99  119.63   32.58    NO
  4500.   7.008        6     1.0      1.0 10000.0   45.99  132.92   34.23    NO
  5000.   6.588        6     1.0      1.0 10000.0   45.99  146.05   35.79    NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND    66. M:
   191.   17.97        3     5.0      5.0  1600.0   19.71   22.95   13.85    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC     DIST TO   TERRAIN
  PROCEDURE         (UG/M**3)     MAX (M)    HT (M)
--------------     -----------    -------   -------
SIMPLE TERRAIN        17.97          191.        0.
```

03/26/12
12:16:46

```
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Copano - Houston Central Gas Plant - HTR-4

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE              =        POINT
   EMISSION RATE (G/S)      =     0.247000
   STACK HEIGHT (M)         =       9.1440
   STK INSIDE DIAM (M)      =       0.4572
   STK EXIT VELOCITY (M/S)=        16.8371
   STK GAS EXIT TEMP (K)    =     477.5944
   AMBIENT AIR TEMP (K)     =     293.1500
   RECEPTOR HEIGHT (M)      =       0.0000
   URBAN/RURAL OPTION       =        RURAL
   BUILDING HEIGHT (M)      =       0.0000
   MIN HORIZ BLDG DIM (M) =         0.0000
   MAX HORIZ BLDG DIM (M) =         0.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX =    3.332 M**4/S**3;  MOM. FLUX =    9.093 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***
```

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
78.	9.242	2	5.0	5.0	1600.0	19.71	15.57	8.78	NO
100.	14.74	2	5.0	5.0	1600.0	19.71	19.49	11.01	NO
200.	17.91	3	5.0	5.0	1600.0	19.71	23.81	14.35	NO
300.	15.96	3	3.0	3.0	960.0	26.76	34.66	20.94	NO
400.	15.44	4	4.5	4.5	1440.0	20.89	29.64	15.63	NO
500.	14.29	4	3.5	3.5	1120.0	24.24	36.40	18.80	NO
600.	13.16	4	3.0	3.0	960.0	26.76	43.01	21.80	NO
700.	12.14	4	2.5	2.5	800.0	30.28	49.56	24.78	NO
800.	11.15	4	2.5	2.5	800.0	30.28	55.90	27.45	NO
900.	10.47	4	2.0	2.0	640.0	35.56	62.34	30.42	NO
1000.	9.722	4	2.0	2.0	640.0	35.56	68.54	32.97	NO
1100.	9.027	4	1.5	1.5	480.0	44.37	74.99	35.58	NO
1200.	8.559	4	1.5	1.5	480.0	44.37	81.07	37.47	NO
1300.	8.096	4	1.5	1.5	480.0	44.37	87.10	39.31	NO
1400.	7.649	4	1.5	1.5	480.0	44.37	93.10	41.11	NO
1500.	7.471	5	1.0	1.0	10000.0	53.55	74.78	30.68	NO
1600.	7.539	5	1.0	1.0	10000.0	53.55	79.17	31.74	NO
1700.	7.562	5	1.0	1.0	10000.0	53.55	83.54	32.78	NO
1800.	7.675	6	1.0	1.0	10000.0	45.99	58.82	22.81	NO
1900.	7.929	6	1.0	1.0	10000.0	45.99	61.68	23.43	NO
2000.	8.142	6	1.0	1.0	10000.0	45.99	64.54	24.05	NO
2100.	8.245	6	1.0	1.0	10000.0	45.99	67.38	24.58	NO
2200.	8.322	6	1.0	1.0	10000.0	45.99	70.22	25.10	NO
2300.	8.377	6	1.0	1.0	10000.0	45.99	73.04	25.60	NO
2400.	8.411	6	1.0	1.0	10000.0	45.99	75.85	26.10	NO

```
   2500.   8.428         6      1.0     1.0 10000.0   45.99   78.66   26.60    NO
   2600.   8.429         6      1.0     1.0 10000.0   45.99   81.45   27.08    NO
   2700.   8.417         6      1.0     1.0 10000.0   45.99   84.23   27.56    NO
   2800.   8.392         6      1.0     1.0 10000.0   45.99   87.00   28.03    NO
   2900.   8.358         6      1.0     1.0 10000.0   45.99   89.77   28.50    NO
   3000.   8.314         6      1.0     1.0 10000.0   45.99   92.52   28.96    NO
   3500.   7.896         6      1.0     1.0 10000.0   45.99  106.18   30.83    NO
   4000.   7.449         6      1.0     1.0 10000.0   45.99  119.63   32.58    NO
   4500.   7.008         6      1.0     1.0 10000.0   45.99  132.92   34.23    NO
   5000.   6.588         6      1.0     1.0 10000.0   45.99  146.05   35.79    NO

 MAXIMUM 1-HR CONCENTRATION AT OR BEYOND    78. M:
    191.   17.97         3      5.0     5.0  1600.0   19.71   22.95   13.85    NO

  DWASH=   MEANS NO CALC MADE (CONC = 0.0)
  DWASH=NO MEANS NO BUILDING DOWNWASH USED
  DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
  DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
  DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

      ***************************************
      *** SUMMARY OF SCREEN MODEL RESULTS ***
      ***************************************

  CALCULATION         MAX CONC    DIST TO   TERRAIN
   PROCEDURE         (UG/M**3)    MAX (M)    HT (M)
 --------------     -----------   -------   -------
 SIMPLE TERRAIN       17.97          191.        0.
```

05/02/12
10:31:39

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

Copano - Houston Central Gas Plant - RTO-3

SIMPLE TERRAIN INPUTS:

SOURCE TYPE	=	POINT
EMISSION RATE (G/S)	=	0.328000E-01
STACK HEIGHT (M)	=	7.6200
STK INSIDE DIAM (M)	=	0.7102
STK EXIT VELOCITY (M/S)	=	25.3990
STK GAS EXIT TEMP (K)	=	477.5944
AMBIENT AIR TEMP (K)	=	293.1500
RECEPTOR HEIGHT (M)	=	0.0000
URBAN/RURAL OPTION	=	RURAL
BUILDING HEIGHT (M)	=	0.0000
MIN HORIZ BLDG DIM (M)	=	0.0000
MAX HORIZ BLDG DIM (M)	=	0.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

BUOY. FLUX = 12.129 M**4/S**3; MOM. FLUX = 49.930 M**4/S**2.

*** FULL METEOROLOGY ***

****
*** SCREEN AUTOMATED DISTANCES ***
****

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
94.	0.1652	3	10.0	10.0	3200.0	21.54	11.99	7.37	NO
100.	0.2287	3	10.0	10.0	3200.0	21.54	12.67	7.78	NO
200.	0.9979	4	20.0	20.0	6400.0	14.26	15.67	8.69	NO
300.	0.9724	4	15.0	15.0	4800.0	16.90	22.77	12.38	NO
400.	0.8765	4	10.0	10.0	3200.0	21.54	29.72	15.78	NO
500.	0.7910	4	10.0	10.0	3200.0	21.54	36.36	18.72	NO
600.	0.7201	4	8.0	8.0	2560.0	25.03	43.01	21.79	NO
700.	0.6395	4	8.0	8.0	2560.0	25.03	49.44	24.54	NO
800.	0.5947	4	5.0	5.0	1600.0	35.47	56.14	27.94	NO
900.	0.5582	4	5.0	5.0	1600.0	35.47	62.39	30.52	NO
1000.	0.5186	4	4.5	4.5	1440.0	38.56	68.70	33.29	NO
1100.	0.4835	4	4.5	4.5	1440.0	38.56	74.83	35.25	NO
1200.	0.4525	4	4.0	4.0	1280.0	42.43	81.05	37.44	NO
1300.	0.4257	4	4.0	4.0	1280.0	42.43	87.09	39.28	NO
1400.	0.4013	4	3.5	3.5	1120.0	47.41	93.25	41.45	NO
1500.	0.3812	4	3.5	3.5	1120.0	47.41	99.20	43.19	NO
1600.	0.3620	4	3.5	3.5	1120.0	47.41	105.11	44.90	NO
1700.	0.3690	5	1.0	1.0	10000.0	75.92	84.85	35.98	NO
1800.	0.3828	5	1.0	1.0	10000.0	75.92	89.14	36.92	NO
1900.	0.3947	5	1.0	1.0	10000.0	75.92	93.41	37.84	NO
2000.	0.4050	5	1.0	1.0	10000.0	75.92	97.67	38.76	NO
2100.	0.4112	5	1.0	1.0	10000.0	75.92	101.91	39.58	NO
2200.	0.4162	5	1.0	1.0	10000.0	75.92	106.14	40.39	NO
2300.	0.4201	5	1.0	1.0	10000.0	75.92	110.36	41.19	NO
2400.	0.4230	5	1.0	1.0	10000.0	75.92	114.56	41.98	NO

2500.	0.4250	5	1.0	1.0	10000.0	75.92	118.75	42.76	NO
2600.	0.4262	5	1.0	1.0	10000.0	75.92	122.93	43.53	NO
2700.	0.4267	5	1.0	1.0	10000.0	75.92	127.09	44.29	NO
2800.	0.4276	6	1.0	1.0	10000.0	64.30	87.87	30.61	NO
2900.	0.4344	6	1.0	1.0	10000.0	64.30	90.61	31.04	NO
3000.	0.4405	6	1.0	1.0	10000.0	64.30	93.34	31.46	NO
3500.	0.4509	6	1.0	1.0	10000.0	64.30	106.89	33.20	NO
4000.	0.4535	6	1.0	1.0	10000.0	64.30	120.26	34.83	NO
4500.	0.4508	6	1.0	1.0	10000.0	64.30	133.49	36.38	NO
5000.	0.4445	6	1.0	1.0	10000.0	64.30	146.57	37.85	NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND 94. M:

233.	1.038	4	20.0	20.0	6400.0	14.26	18.10	9.94	NO

DWASH= MEANS NO CALC MADE (CONC = 0.0)
DWASH=NO MEANS NO BUILDING DOWNWASH USED
DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

****
*** SUMMARY OF SCREEN MODEL RESULTS ***
****

CALCULATION PROCEDURE	MAX CONC (UG/M**3)	DIST TO MAX (M)	TERRAIN HT (M)
SIMPLE TERRAIN	1.038	233.	0.

05/02/12
11:07:04

```
 ***  SCREEN3 MODEL RUN  ***
 *** VERSION DATED 96043 ***

Copano Existing Boiler 3N

SIMPLE TERRAIN INPUTS:
   SOURCE TYPE             =        POINT
   EMISSION RATE (G/S)     =     0.270900
   STACK HEIGHT (M)        =      22.5552
   STK INSIDE DIAM (M)     =       1.2192
   STK EXIT VELOCITY (M/S)=        8.2296
   STK GAS EXIT TEMP (K)   =     566.4833
   AMBIENT AIR TEMP (K)    =     293.1500
   RECEPTOR HEIGHT (M)     =       0.0000
   URBAN/RURAL OPTION      =        RURAL
   BUILDING HEIGHT (M)     =       0.0000
   MIN HORIZ BLDG DIM (M) =        0.0000
   MAX HORIZ BLDG DIM (M) =        0.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.


BUOY. FLUX =   14.470 M**4/S**3;  MOM. FLUX =   13.024 M**4/S**2.

*** FULL METEOROLOGY ***

**********************************
*** SCREEN AUTOMATED DISTANCES ***
**********************************

*** TERRAIN HEIGHT OF    0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***
```

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
37.	0.5936E-16	6	1.0	1.6	10000.0	74.34	8.01	7.91	NO
100.	0.2472E-02	3	10.0	10.8	3200.0	35.40	12.66	7.76	NO
200.	1.204	1	3.0	3.2	960.0	72.61	51.39	31.66	NO
300.	2.588	3	10.0	10.8	3200.0	35.40	34.55	20.75	NO
400.	2.799	3	8.0	8.7	2560.0	39.53	44.95	26.96	NO
500.	2.666	3	8.0	8.7	2560.0	39.53	55.02	32.85	NO
600.	2.592	3	5.0	5.4	1600.0	51.86	65.25	39.22	NO
700.	2.485	3	4.0	4.3	1280.0	59.19	75.22	45.35	NO
800.	2.367	3	3.5	3.8	1120.0	64.42	84.99	51.27	NO
900.	2.245	3	3.0	3.3	960.0	71.40	94.71	57.25	NO
1000.	2.124	3	3.0	3.3	960.0	71.40	104.05	62.71	NO
1100.	2.057	4	5.0	5.6	1600.0	50.59	74.74	35.06	NO
1200.	2.003	4	5.0	5.6	1600.0	50.59	80.84	36.98	NO
1300.	1.937	4	5.0	5.6	1600.0	50.59	86.89	38.84	NO
1400.	1.875	4	4.5	5.1	1440.0	53.82	92.98	40.85	NO
1500.	1.815	4	4.0	4.5	1280.0	57.73	99.05	42.86	NO
1600.	1.763	4	4.0	4.5	1280.0	57.73	104.98	44.59	NO
1700.	1.708	4	4.0	4.5	1280.0	57.73	110.86	46.27	NO
1800.	1.660	4	3.5	4.0	1120.0	62.75	116.85	48.25	NO
1900.	1.615	4	3.5	4.0	1120.0	62.75	122.67	49.86	NO
2000.	1.568	4	3.5	4.0	1120.0	62.75	128.46	51.45	NO
2100.	1.523	4	3.0	3.4	960.0	69.45	134.40	53.46	NO
2200.	1.487	4	3.0	3.4	960.0	69.45	140.12	54.98	NO
2300.	1.450	4	3.0	3.4	960.0	69.45	145.83	56.49	NO
2400.	1.429	5	1.0	1.3	10000.0	88.44	114.45	41.66	NO

```
 2500.   1.470         5     1.0     1.3 10000.0   88.44  118.64   42.45    NO
 2600.   1.506         5     1.0     1.3 10000.0   88.44  122.82   43.22    NO
 2700.   1.539         5     1.0     1.3 10000.0   88.44  126.99   43.99    NO
 2800.   1.567         5     1.0     1.3 10000.0   88.44  131.14   44.74    NO
 2900.   1.593         5     1.0     1.3 10000.0   88.44  135.28   45.49    NO
 3000.   1.615         5     1.0     1.3 10000.0   88.44  139.41   46.23    NO
 3500.   1.684         5     1.0     1.3 10000.0   88.44  159.87   49.80    NO
 4000.   1.701         5     1.0     1.3 10000.0   88.44  180.04   53.21    NO
 4500.   1.668         5     1.0     1.3 10000.0   88.44  199.97   56.07    NO
 5000.   1.621         5     1.0     1.3 10000.0   88.44  219.67   58.80    NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND    37. M:
   414.  2.804         3     8.0     8.7  2560.0   39.53   46.48   27.85    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** INVERSION BREAK-UP FUMIGATION CALC. ***
  CONC (UG/M**3)   =    3.536
  DIST TO MAX (M)  =  2870.39

     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC     DIST TO   TERRAIN
  PROCEDURE         (UG/M**3)     MAX (M)    HT (M)
--------------     -----------    -------   -------
SIMPLE TERRAIN       2.804          414.        0.

INV BREAKUP FUMI     3.536         2870.       --
```

05/18/12
14:26:01

*** SCREEN3 MODEL RUN ***
*** VERSION DATED 96043 ***

Copano - Houston Central Gas Plant - FLARE

SIMPLE TERRAIN INPUTS:

SOURCE TYPE	=	FLARE
EMISSION RATE (G/S)	=	0.239000E-01
FLARE STACK HEIGHT (M)	=	74.6760
TOT HEAT RLS (CAL/S)	=	111613.
RECEPTOR HEIGHT (M)	=	0.0000
URBAN/RURAL OPTION	=	RURAL
EFF RELEASE HEIGHT (M)	=	75.8557
BUILDING HEIGHT (M)	=	0.0000
MIN HORIZ BLDG DIM (M)	=	0.0000
MAX HORIZ BLDG DIM (M)	=	0.0000

THE REGULATORY (DEFAULT) MIXING HEIGHT OPTION WAS SELECTED.
THE REGULATORY (DEFAULT) ANEMOMETER HEIGHT OF 10.0 METERS WAS ENTERED.

BUOY. FLUX = 1.851 M**4/S**3; MOM. FLUX = 1.128 M**4/S**2.

*** FULL METEOROLOGY ***

****
*** SCREEN AUTOMATED DISTANCES ***
****

*** TERRAIN HEIGHT OF 0. M ABOVE STACK BASE USED FOR FOLLOWING DISTANCES ***

DIST (M)	CONC (UG/M**3)	STAB	U10M (M/S)	USTK (M/S)	MIX HT (M)	PLUME HT (M)	SIGMA Y (M)	SIGMA Z (M)	DWASH
94.	0.1059E-07	1	3.0	3.5	960.0	85.69	25.60	13.48	NO
100.	0.7613E-07	1	3.0	3.5	960.0	85.69	27.00	14.23	NO
200.	0.2160E-01	1	2.5	2.9	800.0	87.66	50.08	29.50	NO
300.	0.1737	1	1.0	1.2	320.0	105.35	72.26	48.18	NO
400.	0.3358	1	1.0	1.2	320.0	105.35	93.09	71.66	NO
500.	0.3353	1	1.0	1.2	320.0	105.35	113.35	104.99	NO
600.	0.2643	2	1.0	1.2	320.0	105.35	97.86	62.97	NO
700.	0.2899	2	1.0	1.2	320.0	105.35	112.29	74.38	NO
800.	0.2865	2	1.0	1.2	320.0	105.35	126.49	85.98	NO
900.	0.2689	2	1.0	1.2	320.0	105.35	140.51	97.73	NO
1000.	0.2459	2	1.0	1.2	320.0	105.35	154.35	109.62	NO
1100.	0.2497	3	1.0	1.2	320.0	103.61	112.74	67.18	NO
1200.	0.2536	3	1.0	1.2	320.0	103.61	121.97	72.67	NO
1300.	0.2516	3	1.0	1.2	320.0	103.61	131.14	78.13	NO
1400.	0.2457	3	1.0	1.2	320.0	103.61	140.23	83.55	NO
1500.	0.2374	3	1.0	1.2	320.0	103.61	149.27	88.95	NO
1600.	0.2276	3	1.0	1.2	320.0	103.61	158.24	94.31	NO
1700.	0.2172	3	1.0	1.2	320.0	103.61	167.16	99.65	NO
1800.	0.2066	3	1.0	1.2	320.0	103.61	176.02	104.97	NO
1900.	0.1960	3	1.0	1.2	320.0	103.61	184.84	110.26	NO
2000.	0.1858	3	1.0	1.2	320.0	103.61	193.61	115.53	NO
2100.	0.1760	3	1.0	1.2	320.0	103.61	202.33	120.78	NO
2200.	0.1666	3	1.0	1.2	320.0	103.61	211.01	126.01	NO
2300.	0.1579	3	1.0	1.2	320.0	103.61	219.65	131.21	NO
2400.	0.1496	3	1.0	1.2	320.0	103.61	228.25	136.40	NO
2500.	0.1419	3	1.0	1.2	320.0	103.61	236.81	141.58	NO
2600.	0.1391	4	1.0	1.4	320.0	100.94	162.40	59.81	NO

```
  2700.  0.1403        4     1.0     1.4   320.0  100.94  168.03   61.27    NO
  2800.  0.1411        4     1.0     1.4   320.0  100.94  173.63   62.70    NO
  2900.  0.1415        4     1.0     1.4   320.0  100.94  179.21   64.11    NO
  3000.  0.1415        4     1.0     1.4   320.0  100.94  184.78   65.51    NO
  3500.  0.1372        4     1.0     1.4   320.0  100.94  212.31   71.84    NO
  4000.  0.1299        4     1.0     1.4   320.0  100.94  239.41   77.82    NO
  4500.  0.1217        4     1.0     1.4   320.0  100.94  266.15   83.52    NO
  5000.  0.1133        4     1.0     1.4   320.0  100.94  292.56   88.98    NO

MAXIMUM 1-HR CONCENTRATION AT OR BEYOND    94. M:
   444.  0.3544        1     1.0     1.2   320.0  105.35  102.27   85.98    NO

 DWASH=   MEANS NO CALC MADE (CONC = 0.0)
 DWASH=NO MEANS NO BUILDING DOWNWASH USED
 DWASH=HS MEANS HUBER-SNYDER DOWNWASH USED
 DWASH=SS MEANS SCHULMAN-SCIRE DOWNWASH USED
 DWASH=NA MEANS DOWNWASH NOT APPLICABLE, X<3*LB

 *** INVERSION BREAK-UP FUMIGATION CALC. ***
  CONC (UG/M**3)   =   0.1951
  DIST TO MAX (M)  =  3682.23

     ***************************************
     *** SUMMARY OF SCREEN MODEL RESULTS ***
     ***************************************

 CALCULATION         MAX CONC    DIST TO   TERRAIN
  PROCEDURE         (UG/M**3)    MAX (M)    HT (M)
--------------    -----------    -------   -------
SIMPLE TERRAIN     0.3544          444.        0.

INV BREAKUP FUMI   0.1951         3682.       --
```

Appendix D

Claimed Standard Permit and Permit By Rule

(f) Incorporation of the standard permit into the facility authorization.

(1) Any new facilities or changes in method of control or technique authorized by this standard permit instead of a permit amendment under §116.110 of this title (relating to Applicability) at a previously permitted or standard permitted facility must be incorporated into that facility's permit when the permit is amended or renewed.

(2) All increases in previously authorized emissions, new facilities, or changes in method of control or technique authorized by this standard permit for facilities previously authorized by a permit by rule must comply with §106.4 of this title (relating to Requirements for Permitting by Rule), except §106.4(a)(1) of this title, and §106.8 of this title (relating to Recordkeeping).

Adopted February 9, 2011 Effective March 3, 2011

§116.620. Installation and/or Modification of Oil and Gas Facilities.

(a) Emission specifications.

(1) Venting or flaring more than 0.3 long tons per day of total sulfur shall not be allowed.

(2) No facility shall be allowed to emit total uncontrolled emissions of sulfur compounds, except sulfur dioxide (SO_2), from all vents (excluding process fugitives emissions) equal to or greater than four pounds per hour unless the vapors are collected and routed to a flare.

(3) Any vent, excluding any safety relief valves that discharge to the atmosphere only as a result of fire or failure of utilities, emitting sulfur compounds other than SO_2 shall be at least 20 feet above ground level.

(4) New or modified internal combustion reciprocating engines or gas turbines permitted under this standard permit shall satisfy all of the requirements of §106.512 of this title (relating to Stationary Engines and Turbines), except that registration using the Form PI-7 or PI-8 shall not be required. Emissions from engines or turbines shall be limited to the amounts found in §106.4(a)(1) of this title (relating to Requirements for Permitting by Rule).

(5) Total Volatile Organic Compound (VOC) emissions from a natural gas glycol dehydration unit shall not exceed ten tons per year (tpy) unless the vapors are collected and controlled in accordance with subsection (b)(2) of this section.

(6) Any combustion unit (excluding flares, internal combustion engines, or natural gas turbines), with a design maximum heat input greater than 40 million British thermal units (Btu) per hour (using lower heating values) shall not emit more than 0.06 pounds of nitrogen oxides per million Btu.

(7) No facility which is less than 500 feet from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than ten tpy, but less than 25 tpy, unless the equipment is inspected and repaired according to subsection (c)(1) of this section.

(8) No facility which is 500 feet or more from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 25 tpy unless the equipment is inspected and repaired according to subsection (c)(1) of this section.

(9) No facility which is less than 500 feet from the nearest off-plant receptor shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 25 tpy unless the equipment is inspected and repaired according to subsection (c)(2) of this section.

(10) No facility shall be allowed to emit uncontrolled VOC process fugitive emissions equal to or greater than 40 tpy unless the equipment is inspected and repaired according to subsection (c)(2) of this section.

(11) No facility which is located less than 1/4 mile from the nearest off-plant receptor shall be allowed to emit hydrogen sulfide H_2S or SO_2 process fugitive emissions unless the equipment is inspected and repaired according to subsection (c)(3) of this section. No facility which is located at least 1/4 mile from the nearest off-plant receptor shall be allowed to emit H_2S or SO_2 process fugitive emissions unless the equipment is inspected and repaired according to subsection (c)(3) of this section or unless the H_2S or SO_2 emissions are monitored with ambient property line monitors according to subsection (e)(1) of this section. Components in sweet crude oil or gas service as defined by Chapter 101 of this title (relating to General Air Quality Rules) are exempt from these limitations.

(12) Flares shall be designed and operated in accordance with 40 Code of Federal Regulations (CFR), Part 60.18 or equivalent standard approved by the commission, including specifications of minimum heating values of waste gas,

maximum tip velocity, and pilot flame monitoring. If necessary to ensure adequate combustion, sufficient gas shall be added to make the gases combustible. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes. An automatic ignition system may be used in lieu of a continuous pilot.

(13) Appropriate documentation shall be submitted to demonstrate that compliance with the Prevention of Significant Deterioration (PSD) and nonattainment new source review provisions of the FCAA, Parts C and D, and regulations promulgated thereunder, and with Subchapter C of this chapter (relating to Hazardous Air Pollutants: Regulations Governing Constructed or Reconstructed Major Sources (FCAA, §112(g), 40 CFR Part 63)) are being met. The oil and gas facility shall be required to meet the requirements of Subchapter B of this chapter (relating to New Source Review Permits) instead of this subchapter if a PSD or nonattainment permit or a review under Subchapter C of this chapter is required.

(14) Documentation shall be submitted to demonstrate compliance with applicable New Source Performance Standards (NSPS, 40 CFR Part 60).

(15) Documentation shall be submitted to demonstrate compliance with applicable National Emission Standards for Hazardous Air Pollution (NESHAP, 40 CFR Part 61).

(16) Documentation shall be submitted to demonstrate compliance with applicable maximum achievable control technology standards as listed under 40 CFR Part 63, promulgated by the EPA under FCAA, §112 or as listed in Chapter 113, Subchapter C of this title (relating to National Emissions Standards for Hazardous Air Pollutants for Source Categories (FCAA §112, 40 CFR Part 63)).

(17) New and increased emissions shall not cause or contribute to a violation of any National Ambient Air Quality Standard or regulation property line standards as specified in Chapters 111, 112, and 113 of this title (relating to Control of Air Pollution from Visible Emissions and Particulate Matter; Control of Air Pollution from Sulfur Compounds; and Control of Air Pollution from Toxic Materials). Engineering judgment and/or computerized air dispersion modeling may be used in this demonstration. To show compliance with §116.610(a)(1) of this title (relating to Applicability) for H_2S emissions from process vents, ten milligrams per cubic meter shall be used as the "L" value instead of the value represented by §116.610(a)(1) of this title.

(18) Fuel for all combustion units and flare pilots shall be sweet natural gas or liquid petroleum gas, fuel gas containing no more than ten grains of total sulfur per 100 dry standard cubic feet (dscf), or field gas. If field gas contains more than 1.5

grains of H_2S or 30 grains total sulfur compounds per 100 dscf, the operator shall maintain records, including at least quarterly measurements of fuel H_2S and total sulfur content, which demonstrate that the annual SO_2 emissions from the facility do not exceed the limitations listed in the standard permit registration. If a flare is the only combustion unit on a property, the operator shall not be required to maintain such records on flare pilot gas.

(b) Control requirements.

(1) Floating roofs or equivalent controls shall be required on all new or modified storage tanks, other than pressurized tanks which meet §106.476 of this title (relating to Pressurized Tanks or Tanks Vented to Control), unless the tank is less than 25,000 gallons in nominal size or the vapor pressure of the compound to be stored in the tank is less than 0.5 pounds per square inch absolute (psia) at maximum short-term storage temperature.

(A) For internal floating roofs, mechanical shoe primary seal or liquid-mounted primary seal or a vapor-mounted primary with rim-mounted secondary seal shall be used.

(B) Mechanical shoe or liquid-mounted primary seals shall include a rim-mounted secondary seal on all external floating roofs tanks. Vapor-mounted primary seals will not be accepted.

(C) All floating roof tanks shall comply with the requirements under §115.112(a)(2)(A) - (F) of this title (relating to Control Requirements).

(D) In lieu of a floating roof, tank emissions may be routed to:

(i) a destruction device such that a minimum VOC destruction efficiency of 98% is achieved; or

(ii) a vapor recovery system such that a minimum VOC recovery efficiency of 95% is achieved.

(E) Independent of the permits by rule listed in this paragraph, if the emissions from any fixed roof tank exceed ten tpy of VOC or ten tpy of sulfur compounds, the tank emissions shall be routed to a destruction device, vapor recovery unit, or equivalent method of control that meets the requirements listed in subparagraph (D) of this paragraph.

(2) The VOC emissions from a natural gas glycol dehydration unit shall be controlled as follows.

(A) If total uncontrolled VOC emissions are equal to or greater than ten tpy, but less than 50 tpy, a minimum of 80% by weight minimum control efficiency shall be achieved by either operating a condenser and a separator (or flash tank), vapor recovery unit, destruction device, or equivalent control device.

(B) If total uncontrolled VOC emissions are equal to or greater than 50 tpy, a minimum of:

(i) 98% by weight minimum destruction efficiency shall be achieved by a destruction device or equivalent; or

(ii) 95% by weight minimum control efficiency shall be achieved by a vapor recovery system or equivalent.

(c) Inspection requirements.

(1) Owners or operators who are subject to subsection (a)(7) or (8) of this section shall comply with the following requirements.

(A) No component shall be allowed to have a VOC leak for more than 15 days after the leak is detected to exceed a VOC concentration greater than 10,000 parts per million by volume (ppmv) above background as methane, propane, or hexane, or the dripping or exuding of process fluid based on sight, smell, or sound for all components. The VOC fugitive emission components which contact process fluids where the VOCs have an aggregate partial pressure or vapor pressure of less than 0.5 psia at 100 degrees Fahrenheit are exempt from this requirement. If VOC fugitive emission components are in service where the operating pressure is at least 0.725 pounds per square inch (psi) (five kilopascals (Kpa)) below ambient pressure, then these components are also exempt from this requirement as long as the equipment is identified in a list that is made available upon request by the agency representatives, the EPA, or any other air pollution agency having jurisdiction. All piping and valves two inches nominal size and smaller, unless subject to federal NSPS requiring a fugitive VOC emissions leak detection and repair program or Chapter 115 of this title (relating to Control of Air Pollution from Volatile Organic Compounds), are also exempt from this requirement.

(B) All technically feasible repairs shall be made to repair a VOC leaking process fugitive component within 15 days after the leak is detected. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. The executive director, at his discretion, may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown.

(C) New and reworked underground process pipelines containing VOCs shall contain no buried valves such that process fugitive emission inspection and repair is rendered impractical.

(D) To the extent that good engineering practice will permit, new and reworked valves and piping connections in VOC service shall be so located to be reasonably accessible for leak-checking during plant operation. Valves elevated more than two meters above a support surface will be considered non-accessible and shall be identified in a list to be made available upon request.

(E) New and reworked piping connections in VOC service shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Flanges in VOC service shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

(F) Each open-ended valve or line in VOC service, other than a valve or line used for safety relief, shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

(G) Accessible valves in VOC service shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. For valves equipped with rupture discs, a pressure gauge shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity, but no later than the next process shutdown. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc or venting to a control device are exempt from monitoring.

(H) Dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system, submerged pumps, or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic driven pumps) are exempt from monitoring.

(I) All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

(J) After completion of the required quarterly inspections for a period of at least two years, the operator of the oil and gas facility may request in writing to the Office of Permitting, Remediation, and Registration that the monitoring schedule be revised based on the percent of valves leaking. The percent of valves leaking shall be determined by dividing the sum of valves leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements.

This request shall include all data that has been developed to justify the following modifications in the monitoring schedule.

(i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(ii) After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(2) Owners or operators who are subject to subsection (a)(9) or (10) of this section shall comply with the following requirements.

(A) No component shall be allowed to have a VOC leak for more than 15 days after the leak is found which exceeds a VOC concentration greater than 500 ppmv for all components except pumps and compressors and greater than 2,000 ppmv for pumps and compressors above background as methane, propane, or hexane, or the dripping or exuding of process fluid based on sight, smell, or sound. The VOC fugitive emission components which contact process fluids where the VOCs have an aggregate partial pressure or vapor pressure of less than 0.044 psia at 100 degrees Fahrenheit are exempt from this requirement. If VOC fugitive emission components are in service where the operating pressure is at least 0.725 psi (five Kpa) below ambient pressure, these components are also exempt from this requirement as long as the equipment is identified in a list that is made available upon request by agency representatives, the EPA, or any air pollution control agency having jurisdiction. All piping and valves two inches nominal size and smaller are also exempt from this requirement.

(B) All technically feasible repairs shall be made to repair a VOC leaking process fugitive component within 15 days after the leak is detected. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. The executive director, at his or her discretion, may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown.

(C) New and reworked underground process pipelines containing VOCs shall contain no buried valves such that process fugitive emission inspection and repair is rendered impractical.

(D) To the extent that good engineering practice will permit, new and reworked valves and piping connections in VOC service shall be so located to be reasonably accessible for leak-checking during plant operation. Valves elevated more than two meters above a support surface will be considered non-accessible and shall be identified in a list to be made available upon request.

(E) New and reworked piping connections in VOC service shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Flanges in VOC service shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

(F) Each open-ended valve or line in VOC service, other than a valve or line used for safety relief, shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

(G) Accessible valves in VOC service shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. For valves equipped with rupture discs, a pressure gauge shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity, but no later than the next process shutdown. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc or venting to a control device are exempt from monitoring.

(H) Dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order or seals equipped with an automatic seal failure detection and alarm system, submerged pumps, or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic driven pumps) are exempt from monitoring.

(I) All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

(J) After completion of the required quarterly inspections for a period of at least two years, the operator of the oil and gas facility may request in writing to the Office of Permitting, Remediation, and Registration that the monitoring schedule be revised based on the percent of valves. Leaking. The percent of valves leaking shall be determined by dividing the sum of valves leaking during current monitoring and valves for which repair has been delayed by the total number of valves subject to the requirements. This request shall include all data that has been developed to justify the following modifications in the monitoring schedule.

(i) After two consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip one of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(ii) After five consecutive quarterly leak detection periods with the percent of valves leaking equal to or less than 2.0%, an owner or operator may begin to skip three of the quarterly leak detection periods for the valves in gas/vapor and light liquid service.

(K) A directed maintenance program shall be used and consist of the repair and maintenance of VOC fugitive emission components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be remonitored within 30 days of being placed back into VOC service.

(3) For owners and operators who are subject to the applicable parts of subsection (a)(11) of this section, auditory and visual checks for SO_2 and H_2S leaks within the operating area shall be made every day. Immediately, but no later than eight hours upon detection of a leak, operating personnel shall take the following actions:

(A) isolate the leak; and

(B) commence repair or replacement of the leaking component; or

(C) use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

(d) Approved test methods.

(1) An approved gas analyzer used for the VOC fugitive inspection and repair requirement in subsection (c) of this section, shall conform to requirements listed in 40 CFR §60.485(a) and (b).

(2) Tutweiler analysis or equivalent shall be used to determine the H_2S content as required under subsections (a) and (e) of this section.

(3) Proper operation of any condenser used as a VOC emissions control device to comply with subsection (a)(5) of this section shall be tested to demonstrate compliance with the minimum control efficiency. Sampling shall occur within 60 days after start-up of new or modified facilities. The permittee shall contact the Engineering Services Section, Office of Compliance and Enforcement 45 days prior to sampling for approval of sampling protocol. The appropriate regional office in the region where the source is located shall also be contacted 45 days prior to sampling to provide them the opportunity to view the sampling. Neither the regional office nor the Engineering Services Section, Office of Compliance and Enforcement personnel are required to view the testing. Sampling reports which comply with the provisions of the "TNRCC Sampling Procedures Manual," Chapter 14 ("Contents of Sampling Reports," dated January 1983 and revised July 1985), shall be distributed to the appropriate regional office, any local programs, and the Engineering Services Section, Office of Compliance and Enforcement.

(e) Monitoring and recordkeeping requirements.

(1) If the operator elects to install and maintain ambient H_2S property line monitors to comply with subsection (a)(11) of this section, the monitors shall be approved by the Engineering Services Section, Office of Compliance and Enforcement office in Austin, and shall be capable of detecting and alarming at H_2S concentrations of ten ppmv. Operations personnel shall perform an initial on-site inspection of the facility within 24 hours of initial alarm and take corrective actions as listed in subsection (c)(3)(A) - (C) of this section within eight hours of detection of a leak.

(2) The results of the VOC leak detection and repair requirements shall be made available to the executive director or any air pollution control agency having jurisdiction upon request. Records, for all components, shall include:

(A) appropriate dates;

(B) test methods;

(C) instrument readings;

(D) repair results; and

(E) corrective actions. Records of flange inspections are not required unless a leak is detected.

(3) Records for repairs and replacements made due to inspections of H_2S and SO_2 components shall be maintained.

(4) Records shall be kept for each production, processing, and pipeline tank battery or for each storage tank if not located at a tank battery, on a monthly basis, as follows:

(A) tank battery identification or storage tank identification, if not located at a tank battery;

(B) compound stored;

(C) monthly throughput in barrels/month; and

(D) cumulative annual throughput, barrels/year.

(5) A plan shall be submitted to show how ongoing compliance will be demonstrated for the efficiency requirements listed in subsection (b)(1)(D) of this section. The demonstration may include, but is not limited to, monitoring flowrates, temperatures, or other operating parameters.

(6) Records shall be kept on at least a monthly basis of all production facility flow rates (in standard cubic feet per day) and total sulfur content of process vents or flares or gas processing streams. Total sulfur shall be calculated in long tons per day.

(7) Records shall be kept of all ambient property line monitor alarms and shall include the date, time, duration, and cause of alarm, date and time of initial on-site inspection, and date and time of corrective actions taken.

(8) All required records shall be made available to representatives of the agency, the EPA, or local air pollution control agencies upon request and be kept for at least two years. All required records shall be kept at the plant site, unless the plant site is

unmanned during business hours. For plant sites ordinarily unmanned during business hours, the records shall be maintained at the nearest office in the state having day-to-day operations control of the plant site.

Adopted August 9, 2000 Effective September 4, 2000

SUBCHAPTER W: TURBINES AND ENGINES
§106.511, §106.512
Effective June 13, 2001

§106.511. Portable and Emergency Engines and Turbines.

Internal combustion engine and gas turbine driven compressors, electric generator sets, and water pumps, used only for portable, emergency, and/or standby services are permitted by rule, provided that the maximum annual operating hours shall not exceed 10% of the normal annual operating schedule of the primary equipment; and all electric motors. For purposes of this section, "standby" means to be used as a "substitute for" and not "in addition to" other equipment.

Adopted August 9, 2000 Effective September 4, 2000

§106.512. Stationary Engines and Turbines.

Gas or liquid fuel-fired stationary internal combustion reciprocating engines or gas turbines that operate in compliance with the following conditions of this section are permitted by rule.

(1) The facility shall be registered by submitting the commission's Form PI-7, Table 29 for each proposed reciprocating engine, and Table 31 for each proposed gas turbine to the commission's Office of Permitting, Remediation, and Registration in Austin within ten days after construction begins. Engines and turbines rated less than 240 horsepower (hp) need not be registered, but must meet paragraphs (5) and (6) of this section, relating to fuel and protection of air quality. Engine hp rating shall be based on the engine manufacturer's maximum continuous load rating at the lesser of the engine or driven equipment's maximum published continuous speed. A rich-burn engine is a gas-fired spark-ignited engine that is operated with an exhaust oxygen content less than 4.0% by volume. A lean-burn engine is a gas-fired spark-ignited engine that is operated with an exhaust oxygen content of 4.0% by volume, or greater.

(2) For any engine rated 500 hp or greater, subparagraphs (A) - (C) of this paragraph shall apply.

(A) The emissions of nitrogen oxides (NO_x) shall not exceed the following limits:

(i) 2.0 grams per horsepower-hour (g/hp-hr) under all operating conditions for any gas-fired rich-burn engine;

(ii) 2.0 g/hp-hr at manufacturer's rated full load and speed, and other operating conditions, except 5.0 g/hp-hr under reduced speed, 80-100% of full torque conditions, for any spark-ignited, gas-fired lean-burn engine, or any compression-ignited dual fuel-fired engine manufactured new after June 18, 1992;

(iii) 5.0 g/hp-hr under all operating conditions for any spark-ignited, gas-fired, lean-burn two-cycle or four-cycle engine or any compression-ignited dual fuel-fired engine rated 825 hp or greater and manufactured after September 23, 1982, but prior to June 18, 1992;

(iv) 5.0 g/hp-hr at manufacturer's rated full load and speed and other operating conditions, except 8.0 g/hp-hr under reduced speed, 80-100% of full torque conditions for any spark-ignited, gas-fired, lean-burn four-cycle engine, or any compression-ignited dual fuel-fired engine that:

(I) was manufactured prior to June 18, 1992, and is rated less than 825 hp; or

(II) was manufactured prior to September 23, 1982;

(v) 8.0 g/hp-hr under all operating conditions for any spark-ignited, gas-fired, two-cycle lean-burn engine that:

(I) was manufactured prior to June 18, 1992, and is rated less than 825 hp; or

(II) was manufactured prior to September 23, 1982;

(vi) 11.0 g/hp-hr for any compression-ignited liquid-fired engine.

(B) For such engines which are spark-ignited gas-fired or compression-ignited dual fuel-fired, the engine shall be equipped as necessary with an automatic air-fuel ratio (AFR) controller which maintains AFR in the range required to meet the emission limits of subparagraph (A) of this paragraph. An AFR controller shall be deemed necessary for any engine controlled with a non-selective catalytic reduction (NSCR) converter and for applications where the fuel heating value varies more than ± 50 British thermal unit/standard cubic feet from the design lower heating value of the fuel. If an NSCR converter is used to reduce NO_x, the automatic controller shall operate on exhaust oxygen control.

(C) Records shall be created and maintained by the owner or operator for a period of at least two years, made available, upon request, to the commission and any local air pollution control agency having jurisdiction, and shall include the following:

(i) documentation for each AFR controller, manufacturer's, or supplier's recommended maintenance that has been performed, including replacement of the oxygen sensor as necessary for oxygen sensor-based controllers. The oxygen sensor shall be replaced at least quarterly in the absence of a specific written recommendation;

(ii) documentation on proper operation of the engine by recorded measurements of NO_x and carbon monoxide (CO) emissions as soon as practicable, but no later than seven days following each occurrence of engine maintenance which may reasonably be expected to increase emissions, changes of fuel quality in engines without oxygen sensor-based AFR controllers which may reasonably be expected to increase emissions, oxygen sensor replacement, or catalyst cleaning or catalyst replacement. Stain tube indicators specifically designed to measure NO_x and CO concentrations shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable NO_x and CO analyzers shall also be acceptable for this documentation;

(iii) documentation within 60 days following initial engine start-up and biennially thereafter, for emissions of NO_x and CO, measured in accordance with United States Environmental Protection Agency (EPA) Reference Method 7E or 20 for NO_x and Method 10 for CO. Exhaust flow rate may be determined from measured fuel flow rate and EPA Method 19. California Air Resources Board Method A-100 (adopted June 29, 1983) is an acceptable alternate to EPA test methods. Modifications to these methods will be subject to the prior approval of the Source and Mobile Monitoring Division of the commission. Emissions shall be measured and recorded in the as-found operating condition; however, compliance determinations shall not be established during start-up, shutdown, or under breakdown conditions. An owner or operator may submit to the appropriate regional office a report of a valid emissions test performed in Texas, on the same engine, conducted no more than 12 months prior to the most recent start of construction date, in lieu of performing an emissions test within 60 days following engine start-up at the new site. Any such engine shall be sampled no less frequently than biennially (or every 15,000 hours of elapsed run time, as recorded by an elapsed run time meter) and upon request of the executive director. Following the initial compliance test, in lieu of performing stack sampling on a biennial calendar basis, an owner or operator may elect to install and operate an elapsed operating time meter and shall test the engine within 15,000 hours of engine operation after the previous emission test. The owner or operator who elects to test on an operating hour schedule shall submit in writing, to the appropriate regional office, biennially after initial sampling, documentation of the actual recorded hours of engine operation since the previous emission test, and an estimate of the date of the next required sampling.

(3) For any gas turbine rated 500 hp or more, subparagraphs (A) and (B) of this paragraph shall apply.

(A) The emissions of NO_x shall not exceed 3.0 g/hp-hr for gas-firing.

(B) The turbine shall meet all applicable NO_x and sulfur dioxide (SO_2) (or fuel sulfur) emissions limitations, monitoring requirements, and reporting requirements of EPA New Source Performance Standards Subpart GG--Standards of Performance for Stationary Gas Turbines. Turbine hp rating shall be based on turbine base load, fuel lower heating value, and International Standards Organization Standard Day Conditions of 59 degrees Fahrenheit, 1.0 atmosphere and 60% relative humidity.

(4) Any engine or turbine rated less than 500 hp or used for temporary replacement purposes shall be exempt from the emission limitations of paragraphs (2) and (3) of this section. Temporary replacement engines or turbines shall be limited to a maximum of 90 days of operation after which they shall be removed or rendered physically inoperable.

(5) Gas fuel shall be limited to: sweet natural gas or liquid petroleum gas, fuel gas containing no more than ten grains total sulfur per 100 dry standard cubic feet, or field gas. If field gas contains more than 1.5 grains hydrogen sulfide or 30 grains total sulfur compounds per 100 standard cubic feet (sour gas), the engine owner or operator shall maintain records, including at least quarterly measurements of fuel hydrogen sulfide and total sulfur content, which demonstrate that the annual SO_2 emissions from the facility do not exceed 25 tons per year (tpy). Liquid fuel shall be petroleum distillate oil that is not a blend containing waste oils or solvents and contains less than 0.3% by weight sulfur.

(6) There will be no violations of any National Ambient Air Quality Standard (NAAQS) in the area of the proposed facility. Compliance with this condition shall be demonstrated by one of the following three methods:

(A) ambient sampling or dispersion modeling accomplished pursuant to guidance obtained from the executive director. Unless otherwise documented by actual test data, the following nitrogen dioxide (NO_2)/NO_x ratios shall be used for modeling NO_2 NAAQS;

Device	NO_x Emission Rate (Q) g/hp-hr	NO_2/NO_x Ratio
IC Engine	Less than 2.0	0.4
IC Engine	2.0 thru 10.0	0.15 +(0.5/Q)
IC Engine	Greater than 10.0	0.2
Turbines		0.25
IC Engine with catalytic converter		0.85

(B) all existing and proposed engine and turbine exhausts are released to the atmosphere at a height at least twice the height of any surrounding obstructions to wind flow. Buildings, open-sided roofs, tanks, separators, heaters, covers, and any other type of structure are considered as obstructions to wind flow if the distance from the nearest point on the obstruction to the nearest exhaust stack is less than five times the lesser of the height, Hb, and the width, Wb, where:

Hb = maximum height of the obstruction, and
Wb = projected width of obstruction =

$$2\sqrt{\frac{lw}{3.141}}$$

where:

L = length of obstruction
W = width of obstruction

(C) the total emissions of NO_x (nitrogen oxide plus NO_2) from all existing and proposed facilities on the property do not exceed the most restrictive of the following:

(i) 250 tpy;

(ii) the value (0.3125 D) tpy, where D equals the shortest distance in feet from any existing or proposed stack to the nearest property line.

(7) Upon issuance of a standard permit for electric generating units, registrations under this section for engines or turbines used to generate electricity will no longer be accepted, except for:

(A) engines or turbines used to provide power for the operation of facilities registered under the Air Quality Standard Permit for Concrete Batch Plants;

(B) engines or turbines satisfying the conditions for facilities permitted by rule under Subchapter E of this title (relating to Aggregate and Pavement); or

(C) engines or turbines used exclusively to provide power to electric pumps used for irrigating crops.